Since the mid-1980s, producers and service providers have struggled to remain profitable as unstable oil prices moved generally lower. In the 1990s, oil companies downsized and started relying on outside services for functions that are not considered core business activities. They turned to outsourcing, alliances, partnerships and, lately, to mergers. The oilfield supply sector also restructured, formed joint ventures, consolidated, and began providing integrated products and services to fulfill operator needs. Once again, market conditions and emerging trends are driving the industry to adopt fresh approaches, including better management of oil and gas fields.

To squeeze optimal value from petroleum assets, management of production operations begins at near-well regions of a reservoir, proceeds through completion equipment and surface facilities, and may even extend to sale or export points (next page). Ideally, production management begins before field startup to limit risk and financial exposure, reduce capital investment and minimize time to first commercial output, particularly since many new reservoir discoveries are in frontier areas where expenses are high. For mature reservoirs, this process involves reducing expenses, enhancing productivity and extending field life to improve profitability and maximize recovery. Effective production management may be the difference between saving an asset and divesting or abandoning a property.

This tactical process takes quality, health, safety and environmental (QHSE) as well as economic factors into consideration. Local experience and expertise in applying new or existing technology help reduce costs while optimizing field output and hydrocarbon-processing capacity. Use of innovative methodology is a key element. Because technical, managerial and operational aspects are combined to support optimization and asset development strategies, this renewed emphasis on production differs from traditional outsourcing of field operations, often referred to as contract lease, or pumping, services.

The past 15 years have been extremely dynamic in the upstream petroleum business. Companies continually reinvented and repositioned themselves in response to business pressures and challenges. This article reviews trends behind a production management renaissance and explains why new approaches are needed. In addition to what and why, we discuss how this process is being reengineered, improved and implemented.

New Tactics for Production Management

Focused efforts are helping oil and gas producers realize more economic potential from hydrocarbon assets. Through savvy operating practices and new cooperative relationships with an integrated service provider, field personnel and production analysts use local experience and the latest technology to achieve the best results from available infrastructure, resources, products and services.

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Oilfield Review

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Managing field operations. Production management efforts encompass activities from near-well regions of producing formations through subsurface well completion equipment to surface facility networks that initially process and move hydrocarbons to pipelines for transfer to a point of sale. For oil and gas developments—large or small—a focused process is needed to develop plans, establish budgets, oversee schedules, control capital investments and operating expenses, meet timetables, reduce artificial-lift costs, increase field output, improve hydrocarbon handling and administer joint-interest revenue.
Industry Trends

The upstream petroleum sector has not always performed as well as other industries. Under pressure to increase shareholder return, efficiency and costs were targeted for improvement. As a result, integrated oil and gas companies and large independents began breaking the historically linked, long-chain E&P business into smaller segments that are flexible, efficient and easier to handle. These specialized asset-based units are structured to be more responsive. After restructuring and reorganizing to improve performance, unit resources—properties, employees and suppliers—are consolidated so that a streamlined organization can concentrate on activities in areas where assets can best be exploited.

Service companies, which are also focusing on key competencies and activities that deliver more value or offer the most competitive advantage for clients, are undergoing a similar rationalization.

Breakup of the traditional value chain is causing operators to look hard at organizational effectiveness, and many companies are finding that in-house functions can be improved by partnering with other producers and by forming strategic relationships with service providers through long-term contracts and alliances. Some operators continue to use a periodic low-bid approach that may fulfill immediate needs, but is often counter to finding the best applications for today’s technology and service solutions. Oil and gas companies that consistently emphasize overall production and asset management are setting standards and benchmarks for operations and performance in the next decade.

Long-term relationships have facilitated consolidation in the service sector, which has been a genesis for wider ranges of products and services that deliver customized as well as reliable, cost-effective solutions. Operators, however, now expect service companies to provide integrated processes for products, services and solutions within their areas of expertise (see “Processes Within a Process,” page 6). New product and service combinations applied through the appropriate integrated support process free up operator resources that were previously committed to individual projects, allowing them to be used for other core business functions. In this way, oil companies can add even more value and further
increase shareholder return by directing company energy and efforts toward managing risks, asset portfolios, competitive acreage positions, acquisitions, mergers and exploration programs that replace and add reserves.

Further supporting this trend in service integration is a willingness among operators to base service compensation, or rewards, on results that are achieved and the incremental value added by a service company in proportion to the degree of risk that is shared—value pricing (previous page, top).

More than any other, this factor helps align objectives and set the stage for agreements between producing and service companies to jointly manage production operations.

A type of risk-reward structure is used in the Dacón oil fields of eastern Venezuela. This large-scale project involves redevelopment of a major asset. When the current production contract was awarded in 1998, these fields had 111 active wells and 136 inactive wells, and output was less than 10,000 BOPD [1590 m³/d]. The work scope for alliance partners LASMO and Schlumberger includes seismic data acquisition and evaluation, 300 new wells, 180 remedial well interventions, facility upgrades and artificial-lift optimization. Several teams responsible for design and management of this tactical development effort interact on a daily basis (previous page, bottom). The goal of this technology alliance is to improve output above 90,000 BOPD [14,300 m³/d] and achieve ultimate recovery of at least 35%.

Under this agreement, Schlumberger participates in production management and reservoir optimization by providing products and services on a preferred-supplier basis, but does not have an equity interest. Value pricing for this technology alliance is a gainshare system with incentives based on maximizing project net-present-value (NPV) over a 20-year production contract. Other companies participate through third-party contracts awarded by tender and bids. One year after the fields were handed over to LASMO in April 1998, production had been increased from 10,000 to over 30,000 BOPD [4770 m³/d].

The Case for Change
Oil company asset portfolios encompass numerous properties, some of which include mature fields near the end of the development life cycle when production is declining. Many new fields are in high-cost heavy-oil, gas, deepwater, remote or environmentally sensitive provinces, requiring operators to redirect internal resources. More than ever, because of continually changing market conditions and corporate priorities, producers need the flexibility to access experienced personnel who can work exclusively on a project. Because of downsizing, consolidations, reorganizations, joint ventures and mergers, the older, smaller or nonstrategic fields are often sold, traded, or perhaps worse, ignored. For these types of assets, production management services may be best (above).

Some of these reservoirs will produce at economic rates for many years; others like the Dacón fields can yield more if companies have resources to operate and manage them effectively. Optimal use of critical internal and external resources, and relying on an alliance partner with expertise in a particular area can improve field performance. By using technology and integrated processes to fully exploit reservoirs through improved cost control and efficiency, companies can establish, sustain and, ultimately, increase asset value.

Use of outside providers for some business functions or operating activities, and alliances between clients and service companies that support them are not new to industry in general or the oil and gas sector in particular. Automobile manufacturers were among the first to form alliances with suppliers. These mutual arrangements leveled the playing field for supply companies by stabilizing demand and establishing a base income level that ensured a dependable revenue stream. In return, product and service prices were lower, and automobile companies reduced costs by participating in and helping direct supplier research and development.

Oil and gas producers and service companies benefit from alliances in the same ways as the automobile industry. By the end of the 1980s, cost-reduction efforts by operators resulted in...
Increasing asset value through improved reservoir performance has been pursued for decades, but productivity and recovery results were often difficult, sometimes impossible, to attain because crucial tools and technologies were either unavailable or inadequate. Today, advanced technologies and rigorous process-driven approaches offer ways to reach production goals and take oilfield efficiency to new levels. The IRO Integrated Reservoir Optimization methodology is a well-defined, closed-loop process to help operators maximize reservoir performance (below).1

For new fields, this macro-process represents an approach to understanding reservoirs that encompasses activities from exploration and discovery through reservoir development and production management to abandonment. In existing fields, most, if not all, of these principles can be applied with emphasis on renewing, or rejuvenating, production, and remedial actions to enhance productivity, extend longevity, increase recovery and improve financial results.

For either type of asset, this is a complex task, requiring innovative solutions and the latest fit-for-purpose technology. The IRO process hinges on closing a loop that consists of four principal elements: reservoir characterization through seismic and wireline formation evaluation, reservoir development through petroleum and facility engineering implemented using oilfield drilling and production services, and reservoir management through project, production and asset management, supported by consulting services and permanent downhole monitoring with well process control (see “Controlling Reservoirs from Afar;” page 18). Time-lapse seismic surveys help pinpoint bypassed hydrocarbons, and comprehensive production logs confirm flow profiles and fluid segregation. As more data are collected and analyzed to refine reservoir and economic simulations, a clearer picture of reservoirs emerges to aid decision-making on capital-intensive projects such as infill drilling or horizontal wells to access bypassed formation intervals or natural fractures.

The motivation behind an integrated approach to reservoir optimization was to define step-wise procedures for optimal reservoir development and management as a way of identifying deficits in existing technology and new wellsite services that were needed to improve field production and reserve recovery. For example, areas that will benefit from further technological improvements include enhanced time-lapse seismic acquisition, downhole process control, a new generation of software for geological and reservoir modeling, and revolutionary formation evaluation tools, like the Platform Express well logging platform.2

Processes Within a Process

The complete optimization circuit. Four steps form the IRO Integrated Reservoir Optimization iterative process loop—reservoir evaluation and characterization using oilfield services to acquire, process and evaluate seismic and well log data (1 and 5), reservoir exploitation planning through production management (2 and 6), and reservoir development plan implementation with custom solutions from integrated products and services (3 and 7). The final step is reservoir management, which includes monitoring, control and processes to optimize field operations (4 and 8). During initial appraisal and development (1 through 4), formation properties and conditions are determined along with basic structure and boundaries. Based on drilling and evaluation during subsequent development, exploitation and production (5 through 8), models are updated to better reflect reservoir behavior. For example, compartments may be identified as reservoir assessment proceeds.

1. See reference 2, main text.
3. See reference 1, main text.
The IRO approach represents an extended commitment, often requiring the life cycle of a field—20 years or more in some cases—to achieve full success. While always involving short-term decisions, the IRO process concentrates on major tasks to improve total reservoir performance (above). Production management is a micro-process, a subset of this integrated process, which is used on a daily basis to evaluate and reassess factors that control reservoir behavior and field performance. Development and operating plans are reviewed and updated, revised plans are implemented, and results are monitored against established benchmarks.

Applied within the framework of production management, production enhancement, getting the most production from existing wells, is an important subset of the IRO process and a key to reservoir optimization. Using proven NODAL analysis techniques, a multidisciplinary Production Enhancement Group (PEG) proactively identifies wells with a performance gap between actual and potential productivity—candidate recognition—so remedial action can be taken (below). Production enhancement is one of many functions that drive production management activities by increasing the overall effectiveness of integrated well services, which in turn, are pivotal in improving reserve recovery and maximizing value through reservoir optimization and portfolio-level asset management over longer time periods.

As a key reservoir or asset management tool when field output declines and a key to maintaining plateau oil and gas production for as long as possible, production management is of critical importance.

^Integrated reservoir optimization and production management. The IRO approach incorporates major tasks associated with improving long-term reservoir performance, but also involves making near-term decisions. The production management process flow, which is used to reevaluate and address factors that determine day-to-day reservoir behavior and field performance, is a subset of this process.

^Proactive production enhancement. Closing single-well performance gaps in wells when output is less than potential productivity is the objective of production enhancement. This goal is achieved by applying integrated services and custom solutions that move reservoir inflow performance relationship (IPR) curves up and to the right, and move flow-conduit performance curves down and to the right.
formation of the first oil-industry alliances. These partnerships involved varying levels of participation and took different forms. Alliances have been formed between one or more producers, between producing and service companies, and between product and service suppliers.

Through the 1980s and 1990s, these efforts reduced costs significantly, which improved the industry’s economic picture and financial structure (right). Now, the question is how can performance and efficiency be improved further?

One answer is long-term production management enhanced in four ways: by focusing on key business segments and strategic geographic areas; by optimal use of personnel and resources; by applying appropriate E&P technologies; and by leveraging the competencies of other companies—operators and service. Addressing these factors simultaneously ensures cost-effective operations, helps maintain high reserve-replacement ratios and improves return on investment. A common thread that runs through this process is selection and application of custom integrated solutions over the remaining life of a field. Generating customized solutions to get the most return from oil and gas assets is best achieved through cooperation and the combined strengths of all parties involved.

Managing production was always a service activity, even though traditionally handled by oil company in-house groups. A contract operator or production management team that hires local specialists can concentrate on a project, trim expenses and increase value for asset owners by boosting field output and extending the economic life of a reservoir. Using the best practices for managing production, well and facility interventions, field operations, reservoir performance or entire asset portfolios, an integrated service company can supply engineering design, well drilling and completion planning, artificial-lift optimization, production and injection analysis, joint-interest billing and other financial accounting, including petroleum export marketing for some projects. Production management services can also provide functions ranging from petroleum land, and E&P permit or contract work to exploration and geologic evaluations.

A production management alliance or partnership strengthens GHSE performance, reduces lifting costs, increases field output, improves profitability and adds long-term value. Through ongoing research programs, product development and service expansion, Schlumberger capabilities facilitate production management (see “Integrated Projects and Consulting: A Continuing Commitment,” page 12). Innovative and cost-effective approaches achieve success by combining global expertise and state-of-the-art technology with local experience, and are available when operators have limited infrastructure in a particular location or choose not to use internal resources exclusively, and for large, mature or complex fields.

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Oilfield efficiency. Targeting expenses and performance throughout the 1980s and 1990s significantly impacted the economic picture and cost structure in the upstream petroleum business. Cost reduction efforts during the past 15 years resulted in a 48% decrease in finding and development costs, a 27% drop in lease-operating costs and a 20% reduction in general and administrative costs.

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A New Approach

Day-to-day management of production is tactical, but in practice, it impacts strategic reservoir and asset management. In this way, it differs from contract operations of the past, which focused only on daily or monthly production targets for cost-plus or day-rate compensation. Also, these contract “lease-pumping” arrangements seldom included geoscience or petroleum engineering consulting support. The Schlumberger approach is to provide an alternative process that supports cost-reduction efforts,
delivering initial step-function improvements in lifting costs and further levels of production efficiency later in a project.

This fundamentally new way to manage production enhances asset value through leading-edge technologies, best-in-class products and services, custom solutions, engineering consulting and an integrated process carried out in conjunction with oil and gas company organizations. This comprehensive performance-based effort consists of three principal activities—engineering, intervention and operations. Linked in an integrated process, these activities deliver production management and associated services while overcoming the disadvantages of traditional producer and service-provider relationships (previous page, bottom).

Production management functions include personnel and human resources, information technology, financial issues and accounting, material or equipment procurement and logistics, oilfield services, QHSE compliance, commercial contracts, joint-interest relations and other relationships or communications outside of the alliance. Although targeted initially for onshore basins in North and South America, this model is applicable across geographic regions and offshore.

To achieve mutual objectives and optimal results, operator and Schlumberger organizations must work together to integrate services, processes and management. In a natural progression from multidisciplinary asset groups in an oil company, successful alliances with a service company include a cross section of personnel from each company in a project team that oversees daily operations. Executives from both companies steward long-term goals and performance as members of an oversight committee.

A joint production management effort may involve a Joint Leadership Team (JLT) committee and Joint Project Management Team (JPMT). The JLT integrates the two companies on a management level to align strategic issues, measure performance and determine future goals, objectives and directions for the asset. The JPMT integrates alliance partners and third-party vendors on a tactical level (see “An Alliance to Manage Production,” page 15). Dacian project management in Venezuela is organized using this approach.

The engineering phase includes asset-level and reservoir-level activities. On a technical, basin or regional level, geologic aspects of a project are typically handled by the operating company, or asset owners, as part of their portfolio management and financial responsibilities. This ensures a proper E&P perspective and diligent oversight. Reservoir-specific activities pertinent to production management and reservoir development are a JPMT responsibility. This includes formation evaluation, reservoir performance and economic analyses, and completion technology (above). Production planning, petroleum and facility engineering, data gathering and information processing are part of this phase, which, in addition to technical excellence and strong management skills, requires effective evaluation, planning, budgeting and accounting software.

>Project planning and production engineering. The petroleum and facilities engineering phase of production management involves corporate asset-level, regional-level and basin-level strategies as well as reservoir-level considerations. In a production management service arrangement, asset owners typically address strategic issues, while alliance teams handle activities related to tactical field operations for specific reservoirs. This phase includes reservoir performance and economic analysis, formation characterization and evaluation, and initial completion technology.
The well and facility intervention phase involves new construction or remedial work that encompasses completion technology and design supported by formation evaluation, regulatory and client approval, contingency and risk management, purchasing and material logistics, and drilling or workover activities (left). These activities can be handled by the operator or service company separately, or by a JPMT, depending on contractual agreements or defined project scope. An understanding of field development objectives, planning and cost control, and exceptional QHSE performance are required in this phase.

^ Execution of the development plan. The well and facilities intervention phase of production management consists of well and surface facility upgrades or new construction, formation evaluation support for completion technology and designs, obtaining regulatory and client approvals, managing risks and contingencies, material purchasing and logistics, and well drilling or remedial interventions.

^ Artificial-lift optimization. A systems approach to gas-lift analysis, design and performance monitoring within the framework of a structured production management process increased individual well output rates and helped optimize production from the BP Amoco Forties field in the North Sea.
Managing production operations. Surface and subsurface surveillance, enhancement and maintenance are encompassed by the production operations phase of production management. This phase includes field operations, equipment lease or purchase, maintenance of wells and facilities, control of the production process, hydrocarbon volume reports, finance and revenue accounting, and, in some cases, marketing of produced oil and gas. These activities yield the results of plans formulated in the petroleum and facilities engineering phase.

In the production operations phase, efforts involving production surveillance, enhancement and maintenance can be divided into surface and subsurface processes that include field operations, equipment purchasing or leasing, well and facility maintenance, well-process control and optimization, production volume and revenue reporting, finances and accounting, and hydrocarbon delivery or export (right). This phase yields the results of plans set in motion during the first phase—petroleum and facilities engineering—and includes a feedback loop to provide analysis and evaluations for continually improving the next stage of reservoir development. Rigorous monitoring and control of expenses, production and QHSE performance are required as well as an understanding of field development and production plans, and portfolio-level or asset-level strategies.

Artificial-lift analysis is recommended as an activity during the production operations phase. These evaluations identify inefficiencies and deliver near-term production enhancement. An example of artificial-lift optimization is the BP Amoco Forties field in the North Sea where both gas lift and electric submersible pumps are used. This field has four main platforms produced primarily by gas lift and one lifted solely with electric submersible pumps. Production is declining, but substantial recoverable reserves remain.

Working closely with Camco Products and Services and later the enhanced oil recovery (EOR) group, the operator began submersible pump operations in the late 1980s, and gas-lift systems were installed in the early 1990s. Initially, gas-lift and submersible pump teams concentrated on their specific technology and performance, but over time, a total systems approach evolved that encompassed all aspects of artificial lift, reservoir surveillance and production engineering. Gas-lift optimization involving analysis, design and performance monitoring resulted in incremental rate gains on individual wells (previous page, bottom).

The Schlumberger commitment to reservoir performance optimization and project management began in 1995. In that year, the Integrated Project Management (IPM) organization was formed to fulfill operator requirements through global expertise in combination with local experience. The Production Enhancement Group (PEG) initiative was started and Holditch & Associates was acquired in 1997. This was followed by launch of the IRO Integrated Reservoir Optimization service.

Performance on major projects worldwide has provided extensive integrated service activity and project management experience. During the past four years, these organizations have worked successfully on projects ranging from integrated drilling and well servicing for the North Sea Andrew and Cyrus fields, and the Eastern Trough Area Project (Mungo, Marnock, Machar and Mirren fields) to the Hibernia, Wytch Farm and Machar field alliances. Projects in Africa and South America, like the Dación field redevelopment, are also included in this track record.

Within major or stand-alone projects, production management services have gained acceptance and are increasingly important in the upstream petroleum sector. Acquisition of Coastal Management Corporation (CMC) in 1998 further strengthened Schlumberger capabilities in this area. Formed in 1989, the CMC organization, which developed from a production operating company background, compiled a strong record of implementing projects from large-scale coalbed methane development drilling to production management of major waterflood operations. Schlumberger goals paralleled those of CMC, creating a natural fit that led first to formation of an integrated alliance and then, ultimately, to the acquisition.

In addition to an existing waterflood production management project in West Texas, CMC previously operated the Bryan-Woodbine field near Bryan, Texas, USA, which involved handling working-interest relations and accounting for 435 joint-interest and 15,000 royalty owners, and dealing with complex environmental issues. In the Alabama, USA, Black Warrior basin, CMC scheduled and managed a 14-rig coalbed-methane program for more than a year, drilling more than 400 wells and coordinating a $175 million budget.

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Integrated Projects and Consulting: A Continuing Commitment
Each project had different parameters. The Bryan-Woodbine field involved solving revenue problems. In Alabama, the project included engineering design, accounting, control of capital expenditures and regulatory issues associated with tax credits for unconventional gas.

Recently, the Schlumberger Oilfield Services product lines were reorganized into three product groups—Reservoir Evaluation, Reservoir Development and Reservoir Management—encompassing 13 service segments. These groups develop and support the products and services offered in four existing geographic areas: Asia; Europe, Commonwealth of Independent States and Africa; the Middle East; and North and South America. The Reservoir Evaluation group includes land and marine seismic surveys, and openhole and cased-hole wireline well logging data acquisition, processing and evaluation activities. The Reservoir Development group includes Anadrill, Camco, Dowell and Testing products and services. The Reservoir Management group, which combines GeoQuest, Data and Consulting Services, Production Operators, Inc. from Camco and IPM, supports IRO Integrated Reservoir Optimization and production management processes (right).

Reservoir management embodies several elements, including a strong commitment to excellence in service delivery at the wellsite, integrated solutions and services, alliances, partnerships, value pricing and project management skills. The Reservoir Management group draws on Schlumberger technology and expertise for field development planning and implementation, but also relies on other best-in-class service providers and third parties to form a strong team.

Participation takes several forms, from simple coordination of oilfield services to full involvement in design and management of field operations. To facilitate effective communication and cooperation for life-of-reservoir projects, the importance of involvement during conceptual engineering and detailed design phases is stressed. In addition to a critical mass of operational expertise and a complete range of drilling, completion, development planning and production management services, Schlumberger has forged engineering and construction alliances with premier firms, including Coflexip Stena Offshore, Bechtel Offshore and Fluor Daniel. These arrangements are nonexclusive, with alliance partners representing preferred, first-choice suppliers in various areas.

Substantial improvement in submersible pump run times were also realized (above).

Daily field operations may include operating surface equipment or valves to initiate and control production or increase gas-lift injection rates and pressures for artificial lift, but production enhancement through proactive candidate recognition addresses individual well performance to collectively increase total output from a field. These short-term rejuvenation efforts, which also may be part of the production management process, involve well servicing, modifying or installing artificial lift, pumping matrix acid or hydraulic fracturing stimulation treatments, and other remedial well interventions to improve or renew production.

Developing aligned objectives is essential in any production management initiative. Commercial agreements combine near-term fixed compensation based on lifting-cost improvements with long-term rewards based on adding asset value (below). This model is applied on individual projects, but can be used as a template for future collaboration across an asset portfolio to optimize reservoir performance and maximize value for both the operator and the integrated service provider. A mutual relationship that balances risks and rewards can deliver immediate results and ensure continuous improvement.

An Alliance to Manage Production

In February 1991, Coastal Management Corporation (CMC) was selected from among six companies to provide project management for a group of oil and gas fields in the heart of the Permian Basin of West Texas, USA. CMC was given responsibility for normal operator functions, including general management, exploration and petroleum engineering, field production operations, revenue accounting, joint-interest billing, accounts payable and material procurement.

At the time, the asset operator’s staff was fully committed to other assets and projects. The company estimated that a substantial number of employees would be needed to operate the project, but did not want to expand their organization. Granted authority to manage and operate this project, CMC hired 85 people with local experience and assumed the production management role.

The project, which covers about 80,000 acres (324 km²) and includes more than 1350 active wells (2000 total wells) producing from multiple pay zones over 12 horizons in 47 fields, illustrates the impact of focused production management. Before CMC assumed operations in May 1991, little upside potential was believed to exist in the field, and previous operators had identified this as a noncore asset. A multidisciplinary team was assembled to carry out engineering and geologic evaluations, oversee operations and rejuvenate production output.

Study results led to several actions. Electric submersible pumps were installed in selected wells. With reinterpreted seismic maps, 16 wells were drilled. All but one of these wells were successful. Peripheral waterflood injection patterns were implemented along and between updip edges of overlapping formation sequences across the field (right). These boundaries were identified by two large-scale, Schlumberger-managed three-dimensional (3D) seismic surveys, which also resulted in new field discoveries for this 70-year-old asset.

Seismic survey and waterflood results. A multidisciplinary team carried out engineering and geologic evaluations, managed field operations and began rejuvenating production output. Peripheral waterflood injection patterns were initiated along and between updip edges of overlapping formation sequences identified by two large-scale, three-dimensional (3D) seismic surveys. Several new field discoveries were made as a result of these surveys.
Working closely with a petroleum and facilities engineering team, groups responsible for well and facility intervention, and production operations completed the initial stages of production rejuvenation. Total production rose from about 7000 to almost 12,000 BOPD [1120 to 1906 m³/d] in 1995 (right). Annual capital expenditures of less than $5 million in 1992 were increased each year to $35 million in 1998. Investment results were competitive and rates of return compared favorably with other spending opportunities of the working interest owners.

Control of lease-operating expenses is an important part of effective production management for the project. In addition to the large number of active production and injection wells, there are 37 surface equipment batteries for production separation, three electrical distribution grids and a number of other facility installations in the fields. Lease-operating expenses were reduced from historically high levels, but not to the point of ignoring prudent operating procedures and QHSE practices. With an estimated reserve life of more than 20 years, short-term spending limits are not allowed to override maintenance requirements that will ensure lease equipment and operational longevity.

An integral part of managing lease-operating expenses and overall economic success on the project is the enhanced relationships with vendors who participate directly in repairing wells. The objective was to promote cooperation between operational groups and companies that provide well servicing rigs, pumps and specialty chemicals. Well failure rates, at more than two failures per well per year, exceeded a benchmark of one failure per well per year for similar operations. The dilemma was how to reduce rod, tubing and pump failures. A strong culture of teamwork in the CMC organization pointed to a new model for integrating best-in-class service providers who could add value to the existing production process.

The field organization was restructured around well maintenance activities by organizing field production foremen into a Business Focus Team with management and supervisory personnel from well servicing rig, chemical treatment and subsurface pump companies as members. This team concentrated on improving well maintenance activities. In addition, the task of implementing improvements in the field was assigned to a new Well Reliability Team, again consisting of alliance representatives and specialists from each of the third-party service providers charged with initiating well maintenance improvements. Failures in rods, tubing and subsurface pumps were decreased from 175 per month in 1991 to 40 per month in 1998 (left).

Optimizing production. Before CMC took over operations in May 1991, little upside potential was believed to exist in the field. With reinterpreted seismic maps, 16 wells were drilled. Production rejuvenation included switching to electric submersible pumps for artificial lift in selected wells and peripheral waterflood injection.

Improving efficiency. By implementing well maintenance improvements, rod, tubing and subsurface pump failures were decreased from 175 per month at the end of 1991 to 40 in 1998. This reduced well failure rates from more than two to less than one-half failure per well per year, saving asset owners more than $1 million per year.
Well failure rates were reduced significantly below the benchmark of one per year to less than one-half failure per well per year. As a result, lifting costs were decreased by 34%, and well failures were reduced 75%. These reductions saved working-interest owners more than $1 million over six years. At the same time, efficiency improvements through more direct involvement of the service partners allowed some alliance personnel to move to production management tasks that add more value to the project. Well maintenance cost reductions were achieved while reducing the staff allocated to this activity.

By 1998, these teams had reduced well failures to a point where further improvement was not cost-effective. The focus then shifted from failure reduction to production enhancement. Well servicing specialists have further improved revenue through artificial-lift analysis, optimization and modification. Developing a broader integrated services model than was used in the past—one that provides continuity and concentrates on process activities rather than individual disciplines or narrowly defined tasks—helped achieve these results.

Why is this approach successful? One key is the ability of production management teams to focus energy, creativity, expertise, technology and local experience on a single project and to have the flexibility to analyze problems and develop innovative solutions. Unique because it is a service organization that evolved from a producing company operational background, CMC maintains a life-cycle perspective on the assets it manages. This approach provides a model for coordinating and administering production management activities that is flexible and also delivers maximum field performance.

Project administrative structure is transparent to clients and differs little from any other oil company operation. Through mutually agreeable goals and objectives, both parties share a long-range vision and the corresponding rewards of this value-adding production management process. Developed over ten years of well maintenance and field operating experience, CMC internal systems and methods for managing day-to-day project activities by monitoring and tracking field data allow operations personnel to make cost-effective decisions (below).

### An Ongoing Management Process

Market conditions and emerging business trends offer compelling tactical, strategic and financial incentives to adopt a new production management approach. The challenges of declining production and a mature asset base can be met by altering the way reservoirs are developed and managed from discovery to ultimate depletion and abandonment. By relying on alliances or partnerships for production management, functions and processes developed by an integrated service organization like Schlumberger significantly reduce demands on operator resources—financial and personnel—to acquire, integrate and manage the technologies, products and services involved in field operations. Oil company staffs are able to pursue business opportunities that improve asset value and financial return by redirecting internal resources to activities of greater strategic importance.

Additional advantages come through cost reductions from better application of technology and expertise, more efficient purchasing, pricing and material sources, and expanded R&D capabilities. New approaches to reservoir development and management are not just a repackaged collection of products and services that were offered piecemeal previously in response to client requests; they are customized solutions representing the best technologies and methodologies.

Project management services gained acceptance in the early 1990s. More recently, these arrangements became established as viable methods for meeting near-term tactical objectives and achieving long-range strategic goals. This trend is likely to continue over the next decade as producing companies pursue further production optimization and cost reductions. Controlling current expenses is important, but over the long-term, many mature properties around the world need engineering and operational attention. These petroleum assets contain resources that the world economy needs and producing countries can’t afford to lose as a result of operational oversights or resource limitations. —MET

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^ Production management methodologies. Internal CMC systems and methods developed during a decade of well maintenance, field operating and production management outsourcing experience allow alliance operations personnel to make cost-effective decisions.
Controlling Reservoirs from Afar

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ECLIPSE, TRFC-E (electric tubing-retrievable flow-control valve), Variable Window and WRFC-H (hydraulic wireline-retrievable flow-control valve) are marks of Schlumberger.

Understanding reservoir behavior is difficult enough; controlling it is an even greater challenge. New, remotely operated flow-control technology is helping make full use of reservoir knowledge and increasing production efficiency.

It is human nature to seek to experience the inaccessible. The planet Mars fascinates us, but its remoteness, cold temperatures and thin atmosphere preclude a visit by humans for the time being. Just as it is difficult to study Mars first-hand, we cannot directly view all the complicated interactions within a hydrocarbon reservoir from the Earth’s surface.

In the case of the faraway planet Mars, the special Sojourner rover explored places humans couldn’t. Removing enough rock from a wellbore to accommodate a human would be prohibitively expensive, so we have traditionally used tools conveyed by wireline, coiled tubing or drillpipe during or after well construction to measure and record what we can’t see ourselves.
For a hydrocarbon reservoir, it is not just a matter of satisfying our natural curiosity, though. It is an economic imperative to understand and control what is happening in the reservoir because ignorance can be very costly. For example, significant reserves may be lost to us forever if water bypasses the hydrocarbons and breaks through into a producing well. In addition, fluids in the reservoir might not be flowing where we want or expect them to flow, especially in complex developments featuring multilateral wells and completions in multiple pay zones.

Fortunately, we are now able to deploy downhole completion devices that allow us to not only monitor the well from the surface, but also remotely control flow from specific zones into the well and production tubing. As wells produce fluid from reservoirs, downhole sensors gather real-time or near real-time measurements that can be input to computer programs that help analyze the reservoir and production operations. Engineers can then determine how to adjust downhole valves to optimize production.

Through these advances in completion technology, the industry can increase or accelerate recovery from reservoirs while minimizing risks, lifting costs and expensive well interventions. In this article, we examine downhole measurement and control solutions that optimize production and reserve recovery.

The Complete Picture
The goal of any well completion is to safely, efficiently and economically produce fluids from the reservoir and bring them to the surface. While drilling a well to the desired depth might seem like an end in itself, there are many more operations and decisions that precede production from the wellbore (right). Casing or other tubulars must be designed, selected and installed in the hole along with any tools and equipment needed to convey, pump or control production or injection of fluids. Completion integrity depends on a good cement job or else the completion is compromised from the start. Of course, the completion design must address reservoir type, drive mechanism, fluid properties, well configuration and any complications that might exist, such as sand production or paraffin deposition, for example (next page).

Standard completion technology—cementing casing in the borehole, installing production tubing, packers and other production equipment, and then perforating zones of interest to allow flow from the reservoir to the wellhead—has benefited the industry for decades. Moving forward into new operating environments and more complicated well designs requires better ways to optimize production from wells without risky or possibly ill-timed mechanical intervention. Surface intervention can be extremely difficult. Deepwater or subsea well intervention is often expensive.\(^2\) Completion technology that relies on surface flow-control valves alone precludes selective production from multiple flow units in a single wellbore or one lateral of a multilateral well. In the past, this has resulted in an inability to control production from commingled flow units, crossflow or suboptimal production. The lack of downhole flow-control technology can delay production and negatively affect net present value if each zone is produced sequentially.\(^3\)

The absence of downhole monitoring devices in traditional “dumb iron” completions, which make up the vast majority of completions, results in limited reservoir data. Total flow rate, wellhead pressure and fluid composition might be known from surface measurements, but the actual conditions in a producing zone and the contributions of individual zones cannot be known with certainty unless “smart” measurement devices downhole provide a more complete understanding of what each part of a wellbore contributes. Other options, such as well testing and production logging, provide data from discrete points in time, rather than a continuous history. They present costs and risks, a key risk being the fact that a well test requires interruption of production.

No matter what completion technology and practices are used, reservoirs behave in unexpected ways, particularly new reservoirs about which little is known. The ability to adjust downhole equipment in response to real-time data makes production surprises less worrisome. The first installation of an intelligent completion, by Saga Petroleum in August 1997, initiated an interactive phase in production optimization.\(^4\)

Two years later, fewer than 20 advanced completions exist around the world, but they are increasing reserve recovery and proving their economic and operational worth.

### Advanced Completion Technology

The design goal for intelligent completion devices is safe, reliable integration of zonal isolation, flow control, artificial lift, permanent monitoring and sand control. An intelligent completion is defined as one that provides the ability to both monitor and control at least one zone of a reservoir (below).\(^5\) There are many different names for intelligent, or advanced, completions, but each suggests a significant impact on asset management. Data acquisition, interpretation and the ability to optimize production by remotely adjusting downhole valves distinguish advanced completions from traditional completions and offer the ability to interactively address a situation before it becomes a problem.

The foundation for successful use of surface-operated flow-control equipment downhole is reservoir data that help in decisions about efficient production of reserves. In an ordinary completion, reservoir monitoring occurs only at

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\(^2\) A well intervention might add as much as 30% to the $6 million to $8 million construction cost of a subsea well, whereas the initial intelligent completion might cost less than the intervention and provide better results over the life span of the well. See: Greenberg J: “Intelligent Completions Migrating to Shallow Water, Lower Cost Wells,” *Offshore* 59, no. 2 (February 1999): 63-66.


Specific times. Well tests, production logs and seismic surveys provide one-time snapshots of the reservoir and might not represent the reservoir’s normal behavior or record events that require corrective action. In complex well configurations, such as multilateral wells, production logging is difficult. Simply getting to the reservoir to acquire data can be risky, time-consuming and expensive. Subsequent workover operations, such as plugging and abandoning a zone, can be challenging and costly because a workover rig must be brought to the wellhead and remediation equipment placed in the wellbore.

Permanent downhole gauges are incorporated in intelligent completions to allow continuous data acquisition. Historically, oil company reservoir engineers came up with the idea to monitor downhole conditions in onshore USA wells in the 1960s. The first gauge installations were actually modified wireline equipment. Significant developments in permanent monitoring technology have been made since those early days. Today, permanent gauges have established an impressive worldwide track record for reliably monitoring downhole pressure, temperature and flow rate. Real-time or near real-time pressure, temperature and flow-rate data show the continuous variation in reservoir performance. While second-by-second data collection might seem excessive during routine production operations, the abundance of data ensures that high-quality analysis can be performed when needed.

The wealth of data afforded by permanent gauges means that the reservoir team no longer has to speculate about what is going on downhole. By gathering and analyzing reservoir data, the team can decide if or when adjustments to the completion might be appropriate. Once reservoir behavior has been carefully evaluated, the team can use actual data rather than assumed input values in reservoir simulations and continue operations or adjust downhole conditions using remotely controlled valves operated from surface.

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6. Permanent monitoring and the reliability engineering behind the current generation of permanent gauges will be the focus of an upcoming Oilfield Review article.

Flow-control valves. The WRFC-H hydraulic wireline-retrievable flow-control valve can be adjusted to six positions, one of which is closed. The middle position is a setting that meets anticipated requirements. From this median setting, there can be two adjustments downward or upward to control fluid production or injection.

Field-proven flow-control valves are hydraulically actuated Variable Window valves that can be incrementally adjusted to control the flow area more accurately. In contrast, their less reliable predecessors, sliding sleeves, are either fully opened or completely closed and cannot be adjusted between those two positions. By varying the slot width of the Variable Window valve, flow rates can be adjusted. In essence, the flow rate of each control valve is tailored to the individual zone.

The flow-control valve is mounted in a side-pocket mandrel, or a cylindrical section offset from the tubing, so that the valve can be retrieved by wireline or slickline if necessary (above left). By applying hydraulic pressure, a variable window valve can assume one of six sequential positions to set the rate at which fluids are produced from the formation into the tubing or injected from the tubing into the formation. Reservoir management requires both production and injection capabilities. Check valves prevent crossflow between reservoirs.

An electrically controlled valve is in development (above). The electric version allows infinite adjustment between the opened and closed positions rather than the incremental adjustments of the hydraulic version. Like wireline-retrievable flow controllers, the electrically and hydraulically operated, tubing-retrievable flow controllers in development have no practical depth limitations and can include instruments to measure formation temperature, pressure and flow.
Reliability of flow-control devices is a critical concern because, like permanent gauges, they are meant to last for the life of the well and, with the exception of wireline-retrievable devices, are not usually recovered for repair, maintenance or post-mortem failure analysis. These demands make long-life field trials impractical and identification of risks through other techniques essential. Simple, robust and field-proven equipment is fundamental to the designs. Therefore flow-control valves incorporate proven technology, such as hydraulic motors from subsurface safety valves. Newly developed components have passed rigorous qualification tests.

Initially, it might be difficult to choose from myriad options for completing a wellbore in a new reservoir. Until the reservoir has been characterized to the satisfaction of the operations team, completion specialists recommend ensuring flexibility, continuously acquiring data and then using reservoir-modeling tools to compare predictions with actual results.

**Flow Control in Action**

In two well-known fields, reserves that might have been left in the ground are being recovered through the use of flow-control devices. For example, a thin oil zone in the massive Troll field is being drained by extended-reach or horizontal wells that contact a greater area of the reservoir than vertical wells and reduce the drawdown per unit area to avoid premature gas coning. An innovative multilateral well in the Wytch Farm field enables production from two different sections of an oil reservoir.

Troll field, operated by Norsk Hydro and Statoil, contains the world’s largest offshore gas reserves. There is a thin oil zone below the enormous gas cap. When the field was discovered in the 1970s, and as recently as 1985, technology had not yet been developed to recover the oil reserves. Advances in horizontal drilling now make it possible to drill 3000- to 4000-m [9840- to 13,120-ft] sections horizontally through the relatively uniform, unfaulted sandstone reservoir to drain the oil. Troll C platform, which will begin production during the fourth quarter of 1999, will initially produce oil from a highly permeable sandstone reservoir at a depth of 1580 m [5184 ft] in the Troll Oil Gas Province (below).

The key technical issue for the 40 wells planned from the Troll C platform is to recover oil from the 2- to 18-m [6.5- to 59-ft] thick oil leg without gas coning. The completions, which are subsea, produce oil in the presence of nearby water more readily than in the presence of nearby gas. Use of advanced completion technology was considered at the outset, before drilling the first well from the platform.

A traditional approach in this region would have been a directionally drilled well with a slotted-screen completion (above). The risk in this case is gas or water coning. The preferred approach was to directionally drill the well into the lower part of the oil zone and install a wire-line-retrievable flow-control valve to help with gas lift (right). The well now produces oil and water, but eventually will produce gas. Until then, alternating cycles of production with or without gas lift through the flow-control valve allow oil production without gas coning.

The combination of horizontal drilling technology to drill low in the oil pay, downhole gas-lift technology rather than injection from surface to accelerate production, and downhole flow-control valves enhanced project economics. The elimination of gas-gathering and high-pressure distribution systems helped reduce costs, in part because a smaller, less expensive platform without compression facilities could be used. In the absence of flow-control technology, significant amounts of oil in the Troll field might have been left behind, but advanced completions will improve ultimate recovery by an estimated 60 million barrels of oil (9.5 million m³). At present, five wells in the field have intelligent completions, with four or five more planned for 2000 and seven installations in 2001.
In another example of the use of intelligent completions, record-setting extended-reach wells drain portions of the Triassic Sherwood sandstone reservoir beneath Poole Bay in the Wytch Farm field, operated by BP Amoco in Dorset, England (above). Because these wells are without precedent, the BP Amoco operating team has developed and benefited from a willingness to consider new technologies, resulting in pioneering approaches to well construction and completion design.

The Wytch Farm M-2 well was drilled in 1994. During cementing operations, the cement slurry flash set inside the casing and could not be pumped up the annulus to isolate the sandstone reservoir effectively. The 5¼-in. liner could not be removed, so the team elected to perforate the liner and produce the well. When the water cut rose sharply, the team explored other options for the well. A key economic driver was the internal ceiling on lifting costs. Therefore, during its analysis, the team considered the impact of the completion throughout the life span of the well rather than focusing on the initial cost of the completion.

Around this time, the flow-control device developed by Camco was successfully installed in the Troll field. The Wytch Farm team was motivated to consider applying new technology, such as an adaptation of the flow-control device used in the Troll field. The economics for an advanced completion with flow-control valves were favorable, so the team explored ways to incorporate the new technology in the M-2 wellbore.

Eventually, the group decided to plug the M-2 wellbore and convert the well—renamed the M-15—to a multilateral well with two side-tracks. A multilateral well with an advanced completion functions much like two wells, but without doubling the construction expenses (next page, top). The primary Sherwood sandstone reservoir would be tapped by a simple openhole completion. Another lateral would penetrate a faulted portion of the Sherwood reservoir that had high potential for water production. An electric submersible pump would provide artificial lift (next page, bottom).


Flow-control solution. A multilateral well with three WRFC-H flow-control valves proved to be economically and technically viable because it allowed separate control of each lateral as well as independent testing of each wellbore. The M-15 well is the first in which remotely operated flow-control valves have been installed below an electric submersible pump.

Noncommercial solutions. Drilling two wells would have been prohibitively expensive (left). A single well would have left behind reserves (right).
The M-15 well design addressed three key areas of concern:
- Flow control
- Pressure drawdown
- Well testing.

**Flow control to deal with expected water production from one lateral**—The team anticipated that flow control would allow recovery of an additional 1 million barrels [158,900 m³] of oil that might not have been recovered otherwise.

**Drawdown control to avoid hole collapse in the openhole completion**—The sandstone reservoir drained by the primary lateral was expected to be relatively unfaulted and competent. Casing this lateral would have been uneconomic. The mudstone caprock was penetrated nearly horizontally, so there was potential for collapsing the mudstone if drawdown were higher than a certain specified level. Hole collapse could also damage the electric submersible pump.

**Well testing and data acquisition concerns**—BP Amoco wanted to better understand the production profiles of extended-reach wells by capitalizing on the monitoring equipment planned for the M-15. In addition, a completion with downhole flow control would allow the two branches to be tested independently. The ability to observe the dynamics of the reservoir using downhole equipment, rather than having to interpret ambiguous measurements made at the surface, was a key concern for the team.

After evaluating flow-control devices available at the time, the completion team chose to deploy three WRFC-H hydraulic wireline-retrievable flow-control devices, two in the primary lateral and one in the second lateral. This equipment would allow the water leg predicted in the faulted reservoir to be shut off while producing from the other lateral (above). In addition to flow-control devices, the M-15 equipment includes a third-party flowmeter above and a sensor immediately below the electric submersible pump. The flowmeter measures total flow through the pump, pump discharge pressure and pressure upstream of the flow-control valve that controls the southern lateral. The multisensor, mounted at the bottom of the electric submersible pump, measures fluid and motor-winding temperatures, vibration and intake pressure in the barefoot lateral and uses the pump cable for signal transmission. The multisensor and flowmeter were positioned to help the team understand the performance of each lateral, but early failure of the upper flowmeter impeded investigation of the interaction of the two wellbores. Fortunately, the team was able to establish the integrity of the installation and the drawdown level before gauge failure.

Installation proceeded according to plan. The flow-control equipment continues to allow the two laterals to be controlled individually from the surface.

Shutting off water. Both laterals are producing oil (left). If the lower lateral waters out, the flow-control valve can be closed to prevent water production (right).
Like other extended-reach wells in the Wytch Farm field, the M-15 well set several records. The M-15 has the greatest reach of any dedicated multilateral well. It set additional records with 3400 m [11,155 ft] of horizontal 8½-in. hole in one lateral, 2600 m [8530 m] of 7-in. liner floated into position, whipstock retrieval at 5300 m [17,390 ft] and 85 degrees, and 1800 m [5905 ft] of perforating guns run to 8000 m [26,248 ft]—a record since broken by the M-16 well. It is also the first well worldwide in which a surface-controlled flow device has been installed below an electric submersible pump.

The M-15 example confirms that flow-control devices work as designed, so future decisions about using them will be based on project economics and long-term performance reliability. Installing advanced completion equipment requires a properly trained wellsite crew. Careful preparation is a key to success. A completion similar to the Wytch Farm M-15 example would be appropriate in other areas to control drawdown or water production from layered reservoirs and reservoirs with high contrasts in pressure, permeability and water cut.

Currently, advanced completions are used in areas where interventions are most costly—deepwater, arctic and environmentally sensitive locations—which also tend to have more complicated wells. To date, five valves have been installed in the Troll field and three valves in the Wytch Farm completion, all of which continue to function.

Other applications of flow-control valves and permanent gauges are available. For example, in a field that has gravity-drainage oil production, downhole gas production and autoinjection may eliminate the need for gas-production and gas-injection wells, in addition to replacing costly surface facilities (right). Such downhole repressuring in the wellbore is not only cost-effective, but environmentally more benign.


Another application is for commingling production in stacked reservoirs with potential for crossflow or in areas where government regulations require separate accounting for production from separate hydrocarbon zones. In fields undergoing secondary recovery, such as water-floods, flow-control devices and permanent gauges can help maintain critical injection rates. This will help avoid premature breakthrough caused by injecting fluid too rapidly and prevent inefficient displacement of reservoir fluids due to an injection rate that is too low. Clearly, remote monitoring and control of flow can address complications presented by multiple reservoirs, multiple fluid phases, formations that are sensitive to drawdown pressures and complex well configurations.
Future Remote Monitoring and Flow Control

Monitoring and controlling flow from the surface are the first stages in optimizing reservoir plumbing. Ideally, future reservoir management will routinely involve observation and data gathering, interpretation and intervention (below). Dynamic updating of the reservoir model using feedback from real-time monitoring maximizes the value of the data and allows the operator to make informed adjustments to downhole valves that control flow from the reservoir by determining the optimal flow.

To assess the impact of real-time data collection and flow control on recovery, a laboratory experiment was designed by the Reservoir Dynamics and Control group at Schlumberger-Doll Research, Ridgefield, Connecticut, USA. The experimental apparatus simulates a deviated well in an oil reservoir near an oil-water contact (right). The Berea sandstone reservoir in the experiment was saturated with fresh water to represent oil in an actual reservoir. The “oil” was displaced by salt water that represents connate water in an actual reservoir.

The “well” has three flow-control valves. When the valves were opened fully, “oil” production was followed by early “water” breakthrough at the deepest completion in the wellbore because this part of the well is closest to the “oil-water” contact and is the path of least resistance. Consequently, the reservoir was poorly swept.

An optimal production strategy was then designed using the model that had been prepared for the laboratory reservoir. A simulation, performed with ECLIPSE reservoir simulation software, was linked to an optimization algorithm that incorporated an objective of maximum recovery and practical constraints, such as the reservoir pressure at each part of the wellbore, fixed total production rate and maximum water cut. The simulation showed that more oil could be recovered by varying the offtake in the different segments of the well. By adjusting the valves in the next phase of the experiment, more “oil” was indeed recovered because the “water” front approached the wellbore evenly rather than breaking through one zone of the completion prematurely.

14. The Berea 500 sandstone, a quartz-rich, Lower Carboniferous sandstone from Ohio that is prized for its durability, is widely used in petroleum industry tests. For more on the Berea sandstone: http://www.amst.com/red_sandstone_products.html.
In the experiment, adjustment of flow into each of the valves was made on the basis of observations of the front movement using computer-assisted tomographic scans (left). In subsurface reservoirs it will also be necessary to image the front movement in order to devise a control strategy, and research is under way to develop reliable sensors for this purpose.

The experiment clearly demonstrated that producing each zone at its optimal rate improves hydrocarbon recovery from the well (below left). When the valves in the wellbore were fully opened, only 75% of the “oil” was displaced. By judiciously adjusting the three valves in the experimental apparatus, sweep efficiency increased to 92%.

State-of-the-art monitoring and flow-control technology minimize the need for well interventions and make those that are necessary more cost-effective by simplifying them or timing them optimally. As demonstrated in the Wytch Farm and Troll field examples, additional incremental reserve recovery is more likely when individual zones or wellbores can be operated independently, produced at precise rates to avoid water or gas coning or excessive drawdown, and assisted by artificial-lift systems.

Intelligent completions also affect the way people work. Design of these systems involves closer interactions on a technical basis between operators and service and equipment providers to ensure safer and more effective completions. A remotely operated intelligent completion may reduce the number of people needed at the wellsite, so field operations become less expensive and more people can remain in their offices.

Application of this technology is in its infancy—there are now fewer than 20 advanced completions worldwide. Advanced completion technology is currently most useful in high-cost areas, but ultimately will enter lower tier cost markets as the technology is simplified and proven in other operating theaters. A future challenge will be to build intelligent completions equipment for casing less than 7-in. in diameter. The combination of the expertise of Camco in flow-control valves and the track record of Schlumberger in downhole electronics offers a unique ability to both monitor and control flow. The joint efforts of reservoir specialists and completion experts will put downhole process control on the road to ubiquity.

—GMG
Fighting Scale—Removal and Prevention

Imagine an oilfield menace that can smother a productive well within 24 hours. The buildup of scale inside wellbores does exactly that, causing millions of dollars in damage every year. New understanding of scale accumulation is allowing production engineers to predict when scale formation will occur, so that adverse operating conditions can be prevented with new inhibitor techniques. New tools are also available to blast scale away from casing and tubulars.

Few production problems strike fear into the hearts of engineers the way scale can. Scale is an assemblage of deposits that cake perforations, casing, production tubing, valves, pumps and downhole completion equipment, thereby clogging the wellbore and preventing fluid flow. Scale, just like the scale found in home plumbing or tea kettles, can be deposited all along water paths from injectors through the reservoir to surface equipment. Most scale found in oil fields forms either by direct precipitation from the water that occurs naturally in reservoir rocks, or as a result of produced water becoming oversaturated with scale components when two incompatible waters meet downhole. Whenever an oil or gas well produces water, or water injection is used to enhance recovery, there is the possibility that scale will form. In some areas, such as the North Sea and Canada, where entire regions are prone to scale, it is recognized as one of the top production problems.

Scale can develop in the formation pores near the wellbore—reducing formation porosity and permeability. It can block flow by clogging perforations or forming a thick lining in production tubing (above). It can also coat and damage downhole completion equipment, such as safety...
valves and gas-lift mandrels. The effects of scale can be dramatic and immediate: in one North Sea well in the Miller field, engineers were shocked to see production fall from 30,000 B/D [4770 m³/d] to zero in just 24 hours. The costs can be enormous also. Curing scale problems costs the industry hundred of millions of dollars per year in lost production. Until recently, ways to treat the problem were limited and sometimes ineffective. When scale forms, a fast, effective removal technique is needed. Scale-removal methods involve both chemical and mechanical approaches, each with its own niche—depending on the location of the scale and its physical properties.

Some mineral scales, such as calcium carbonate [CaCO₃], can be dissolved with acids, while most others cannot. Sometimes tar-like or waxy coatings of hydrocarbons protect scale from chemical dissolvers. Accumulated solid layers of impermeable scale can line production tubing, sometimes completely blocking it, and are less easily removed. Here, mechanical techniques or chemical treatments are traditionally used to cut through the scale blockages. Nevertheless, common hard scales, such as barium sulfate [BaSO₄], are extremely resistant to both chemical and mechanical removal. Before recent developments in scale-removal technology, operators with hard-scale problems in their production tubing were often forced to shut down production, move in workover rigs to pull the damaged tubing out of the well, and either treat for scale at the surface or replace the tubing.

In this article, we review the physical causes of scale buildup during oil production. Knowing the conditions that lead to scaling and when and where it occurs helps in understanding how to remove scale and in designing intervention treatments to restore long-term well productivity. Then, we survey the chemical and mechanical techniques used in scale removal—including the latest developments in jetting techniques—and examine the strengths and limitations of each approach. Finally, we look at advances in water treatments and new inhibitors that help control the delicate chemical balance to prevent scale precipitation from recurring.

Mineral solubilities have a complex dependency on many variables including temperature (top), pressure (center) and salinity (bottom).

Sources of Scale
In oilfield scale, water is of primary importance, since scale will occur only if water is produced. Water is a good solvent for many materials and can carry large quantities of scaling minerals. All natural waters contain dissolved components acquired through contact with mineral phases in the natural environment. This gives rise to complex fluids, rich in ions, some of which are at the saturation limit for certain mineral phases. Seawater tends to become rich in ions that are by-products of marine life and water evaporation. Ground water and water in the near-surface environment are often dilute and chemically different from deep subsurface water associated with gas and oil.

Deep subsurface water becomes enriched in ions through alteration of sedimentary minerals. The water in carbonate and calcite-cemented sandstone reservoirs usually contains an abundance of divalent calcium [Ca²⁺] and magnesium [Mg²⁺] cations. Sandstone formation fluids often contain barium [Ba²⁺] and strontium [Sr²⁺] cations. In reservoir fluids total dissolved solids can reach 400,000 mg/L [3.34 ppg]. The precise composition has a complex dependence on mineral diagenesis and other types of alteration encountered as formation fluids flow and mix over geological time.

Scale begins to form when the state of any natural fluid is perturbed such that the solubility limit for one or more components is exceeded. Mineral solubilities themselves have a complicated dependence on temperature and pressure. Typically, an increase in temperature increases the water solubility of a mineral. More ions are dissolved at higher temperatures (below). Similarly, decreasing pressure tends to decrease...
solubilities and, as a rule-of-thumb, the solubility of most minerals decreases by a factor of two for every 7000-psi [48-MPa] decrease in pressure.

Not all minerals conform to the typical temperature trend; for example, calcium carbonate shows the inverse trend of increasing water solubility with decreasing temperature. The solubility of barium sulfate increases by a factor of two in the temperature range 25°C to 100°C [77°F to 212°F] and then decreases by the same magnitude as temperatures approach 200°C [392°F]. This trend is itself influenced by the background brine salinity.

An additional complexity is the solubility of carbonate minerals in the presence of acid gases such as carbon dioxide [CO₂] and hydrogen sulfide [H₂S]. Carbonate solubility increases as fluid acidity increases, and CO₂ or H₂S at high pressure supply significant acidity. Consequently, formation waters, in contact with both carbonate rock and acid gases, can be rich in dissolved carbonate. This trend has a complex nonlinear dependence on brine composition, temperature and the pressure of the gas above the liquid phase; this gas pressure effect is orders of magnitude greater than the normal effect of pressure on the solubility of a mineral. Generally, as pressure falls, CO₂ leaves the water phase causing the pH to rise—leading to calcite scale formation.

Forming Scale

Although the driving force for scale formation may be a temperature or pressure change, outgassing, a pH shift, or contact with incompatible water, many produced waters that have become oversaturated and scale-prone do not always produce scale. In order for a scale to form it must grow from solution. The first development within a saturated fluid is a formation of unstable clusters of atoms, a process called homogeneous nucleation (left). The atom clusters form small seed crystals triggered by local fluctuations in the equilibrium ion concentration in supersaturated solutions. The seed crystals subsequently grow by ions adsorbing onto imperfections on the crystal surfaces—extending the crystal size. The energy for seed crystal growth is driven by a reduction in the surface free energy of the crystal, which decreases rapidly with increasing radius after a critical radius is exceeded. This implies that large crystals favor continuing crystal growth, and also implies that small seed crystals may redissolve. Thus, given a large enough degree of supersaturation, the formation of any seed crystal will encourage an increase in the growth of scale deposits. The seed crystal, in effect, is a catalyst for scale formation.

Crystal growth also tends to initiate on a pre-existing fluid-boundary surface, a process called heterogeneous nucleation. Heterogeneous nucleation sites include surface defects such as pipe surface roughness or perforations in production liners, or even joints and seams in tubing and pipelines. A high degree of turbulence can also catalyze scale deposition. Thus, the accumulation of scale can occur at the position of the bubblepoint pressure in the flowing system. This explains why scale deposits rapidly build on downhole completion equipment. Through this understanding of nucleation phenomena, scale inhibitors—discussed later—have been developed that use chemicals specifically designed to poison the nucleation and growth stages of scale formation and reduce the rate of scale formation to almost zero.

Nucleation processes. Scale growth starts in supersaturated solutions with ion pairs forming single crystals in solution, called homogeneous nucleation (top). Scale can also grow on preexisting surface defects—such as rough spots on the liquid-tubing surface, called heterogeneous nucleation (bottom).

Scale in tubing. The location of scale deposits in tubing can vary from downhole perforations to the surface where it constrains production through tubing restrictions, blocked nipples, fish, safety valves and gas-lift mandrels. Scale is often layered and sometimes covered with a waxy or asphaltene coating (insert). Pitting and corrosion on steel can develop under the scale due to bacteria and sour gas, diminishing steel integrity.
Identifying Scale

Identifying the location and composition of the scale deposit is the first step in designing a cost-effective remediation program.

Production tubing and surface equipment—

Scale in production tubing may occur as a thick layer adhering to the inside of the tubing. It is often centimeters thick and has crystals up to 1 cm or larger. The primary effect of scale growth on tubing is to lower the production rate by increasing the surface roughness of the pipe and reducing the flowing area. The driving pressure therefore goes up and the production goes down. If mineral growth increases, then access to lower sections of the well becomes impossible, and ultimately the growth blocks production flowing through the tubing (previous page, bottom right).

Tubing scale varies in chemical composition, being composed of layers of scale deposited during the well’s history. Often, scales include asphaltene or wax layers, and the layers of scale that are closest to the tubing may contain iron sulfides, carbonates or corrosion products.

Near-wellbore matrix—The carbonate or sulfate scale that is typical of the near-wellbore region has a finer particle size than tubing scale, on the order of nanometers rather than centimeters. It blocks gravel packs and screens as well as matrix pores. Near-wellbore scale commonly forms after long periods of well shut-in because crossflow mixes incompatible waters from different layers. Such scale is thought of as skin (above right). Removal by chemical dissolvers or acids can increase production rates dramatically.

Injector wells—Scale damage to injection wells is usually caused by temperature-activated autoscaling of the injection water. In addition, incompatible mixing can occur in the near wellbore when injection water contacts either natural formation water or completion brine (right). This problem is limited to the early stages of injection, when injection water is contacting incompatible water in the near-wellbore region. Scale formed here can decrease the permeability of the formation and reduce the effectiveness of the waterflood strategy.

Detecting scale—Physical evidence of scale exists as samples of tubing scale or X-ray evidence from core analysis. Gamma ray log interpretation often indicates barium sulfate scale since naturally radioactive radium Ra.

precipitates with this scale. As much as a 500-API increase in gamma ray activity over natural background has been seen in many cases.

Evaluating production using NODAL analysis can indicate tubing scale if a well suddenly demonstrates tubing constraints that were not present during early production. In theory, NODAL analysis can indicate scale in matrix through the identification of increasing reservoir constraints on production, although this is difficult to distinguish from other forms of formation damage.

The onset of water production is often a sign of potential scale problems, especially if it coincides with simultaneous reduction in oil production. Normally, operators track water chemistry and in particular the dissolved ion content of the produced water. Dramatic changes in the concentrations of scaling ions, such as Ba or sulfate [SO4], that coincide with reduced oil production and increased water cut, can signal that injection water has broken through and scale is beginning to form. Inspection of the response to previous chemical interventions, such as acid treatments, can give weight to such interpretations.

Early warning of scaling conditions would be valuable to operators, since wells can scale up within 24 hours or less. Wells with intelligent completions and permanent monitoring systems are being designed to detect changes in water chemistry. Downhole scale sensors and permanent monitoring applications are areas of active research. For example, BP Amoco initiated an integrated scale management system that uses a downhole electrochemical sensor sensitive to pH and chloride ion concentrations along with temperature, pressure and multiphase flow measurements to detect potential carbonate buildup and help regulate chemical dosages for scale control.

Chemical modeling—Chemical models are now available to predict the nature and extent of scaling from detailed fluid conditions. These models predict phase equilibrium using thermodynamic principles and geochemical databases. All rely on basic input data such as elemental-concentration analysis, temperature, pressure and gas-phase compositions. These programs are designed to predict the effect of perturbations such as incompatible mixing or changes in temperature and pressure.
Many scale-prediction programs are now available as public domain software and a limited number of commercial computer programs tailored specifically to the simulation of oilfield brine chemistry. These programs range from spreadsheet models to highly developed geochemical models designed to simulate fluid and chemical transport in porous formations. Such simulators can be used to predict scaling problems far into the future, using scenarios of reservoir performance and expected water breakthrough. In fact, for new reservoirs that have no history of scaling problems, chemical models are the only available predictive tools. Still, simulators require highly accurate chemical composition data for virgin reservoir fluids and injection waters. These are rarely available, but can be collected to provide more accurate predictions of scale formation.

Common Scaling Scenarios

Four common events typically encountered in hydrocarbon production give rise to scale.

1. Incompatible mixing—Mixing incompatible injection and formation waters can cause scale formation. Seawater is often injected into reservoirs during secondary and enhanced-recovery waterflooding operations. Seawaters are typically rich in \( \text{SO}_4^{2-} \) anions with concentrations often above 2000 mg/L [0.02 ppm], while formation waters contain divalent cations \( \text{Ca}^{2+} \) and \( \text{Ba}^{2+} \). Fluid mixing in the near-wellbore matrix generally produces new fluids with combined ion concentrations that are above the solubility limits for sulfate minerals. Calcium sulfate \([\text{CaSO}_4]\) scale forms in limestone formations, and barium sulfate \([\text{BaSO}_4]\) and strontium sulfate \([\text{SrSO}_4]\) scales form in sandstone formations (below). If these scales form in the formation, they are difficult to remove chemically and impossible to remove mechanically. Incompatible water mixing can also occur in tubing, producing scales that are accessible to both chemical and mechanical removal.

2. Autoscaling—A reservoir fluid experiences changes in temperature and pressure as it is produced. If such changes take the fluid composition beyond the solubility limit for a mineral, it will precipitate as scale—this phenomenon is called autoscaling or self-scaling. Sulfate and carbonate scales can precipitate as a result of pressure changes within the wellbore or at any restriction downhole. Sodium chloride scale (halite) forms in a similar way from highly saline brines undergoing large temperature drops. Water can carry 100 lbm/bbl [218 kg/m³] of halite at 200°C, but only 80 lbm/bbl [174 kg/m³] at surface temperatures. Halite can precipitate at the rate of 20 lbm for each barrel of water produced, leading to many tons of scale every day in a single well producing water at a rate of 1000 B/D [159 m³/d].

Another serious problem occurs when carbonate scales precipitate from produced fluids containing acid gases. Reduction in pressure during production outgasses the fluid, which raises pH and causes scale deposition. The deposition of carbonate can extend from the near-wellbore matrix, along tubing and into surface equipment as the produced water continuously changes in pressure and temperature.

For carbonate scales, temperature effects often work against pressure effects. For example, the pressure drop at the point of entry into the wellbore can lead to matrix scale. As the fluid progresses up the tubing to surface temperatures and wellhead pressure, the resulting temperature drop may override the pressure effect, reducing scale formation in the tubing. On the other hand, subsequent release of pressure from the wellhead to surface can lead to massive deposits of scale in surface equipment and tubing.

Evaporation-induced scale—Scale formation is also associated with the simultaneous production of hydrocarbon gas and formation brine (wet gas). As the hydrostatic pressure in production tubulars decreases, the volume of the hydrocarbon gas expands and the still hot brine phase evaporates. This results in dissolved ions being concentrated in excess of mineral solubilities in the remaining water. This is a common cause of halite scaling in high-pressure, high-temperature (HTHP) wells, but other scales may also form this way.

Gas flood—Flooding a formation with \( \text{CO}_2 \) gas for secondary recovery can result in scale deposition. Water containing \( \text{CO}_2 \) becomes acidic and will dissolve calcite in the formation. Subsequent pressure drops in the formation surrounding a producing well can cause \( \text{CO}_2 \) to break out of solution and cause carbonate scale to precipitate in the perforations and in formation.

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**Brine Composition of Two Different Waters**

<table>
<thead>
<tr>
<th>Ion species</th>
<th>Formation water, ppm</th>
<th>Seawater, ppm</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sodium</td>
<td>31,275</td>
<td>10,890</td>
</tr>
<tr>
<td>Potassium</td>
<td>654</td>
<td>460</td>
</tr>
<tr>
<td>Magnesium</td>
<td>379</td>
<td>1368</td>
</tr>
<tr>
<td>Barium</td>
<td>269</td>
<td>0</td>
</tr>
<tr>
<td>Strontium</td>
<td>771</td>
<td>0</td>
</tr>
<tr>
<td>Sulfate</td>
<td>0</td>
<td>2960</td>
</tr>
<tr>
<td>Chloride</td>
<td>62,412</td>
<td>19,765</td>
</tr>
<tr>
<td>Calcium</td>
<td>5038</td>
<td>428</td>
</tr>
</tbody>
</table>

---

> Scale from incompatible waters. The table (top) shows typical differences in ion concentrations found in formation water and seawater. The graph (bottom) shows the amount of scale that precipitates from different mixtures of seawater and formation water.

---

pores near the wellbore. The production of scale in the near-wellbore environment will cause a further reduction in pressure and even more precipitation (above). Like autoscaling, this self-generating process can completely seal perforations or create an impermeable wall between the borehole and reservoir within a few days, completely shutting down production.

Scale Removal

Scale-removal techniques must be quick, non-damaging to the wellbore, tubing or formation environment, and effective at preventing reprecipitation. Formation matrix stimulation treatments frequently employ scale dissolvers to arrest production decline. The best scale-removal technique depends on knowing the type and texture. A poor choice of removal method can make an impermeable scale deposit. The best scale-removal approach, especially when scale is not easily accessible or exists where conventional mechanical removal methods are ineffective or expensive to deploy. For example, carbonate minerals are highly soluble in hydrochloric acid and therefore can be easily dissolved. Hard sulfate scale is more difficult because the scale has a low acid solubility. In the formation matrix, it can be treated by the use of strong chelating agents, compounds that break up acid-resistant scale by isolating and locking up the scale metallic ions within their closed ring-like structure.

Most chemical treatments are controlled by how well the reagents gain access to the scale surface. Consequently, the surface-area-to-volume ratio, or equivalently the surface-area-to-mass ratio, is an important parameter in the speed and efficiency of the removal process. Large reactant surface areas, such as porous materials, clay-like particles of extremely thin plates, and hair-like projections react quickly, since the acid or reactant volume surrounding the surface is large. Smaller surface-area-to-volume in thick, nonporous sheets of scale are slow to react with any but the strongest chemical reactants. Scale deposits in tubing exhibit such a small surface area for a large total deposited mass that the reactivity of chemical systems is usually too slow to make chemical treatment a practical removal method.

Frequently high-permeability zones in the formation—offering a path of least resistance—divert treatment fluids, and hinder the ability of scale dissolvers to penetrate the intervals damaged by scale. Novel techniques using dissolvers and preflushes containing viscoelastic surfactants can enhance dissolver placement. Viscoelastic surfactants form high-viscosity gels when mixed with specific brine compositions, but completely break down and become water-like in the presence of oil or hydrocarbon gas. Therefore, these viscoelastic surfactants help channel the scale dissolvers into productive oil-saturated zones, avoiding nonproductive water-saturated zones.

Although hydrochloric acid is usually the first choice for treating calcium carbonate scale, the rapid acid reaction may hide a problem: spent acid solutions of scale by-products are excellent initiators for reformation of scale deposits. For example, a field study evaluating matrix stimulation with acid, helped an operator in the North Sea interpret declining production rates (below). By comparing well production histories in the

\[ \text{Normalized flow} \]

![Diagram of production well damage](image)

\[ \text{Saw-tooth production profiles. A portion of the production history from one of the prolific wells in the Gullfaks field shows cyclic production impairment. The normalized flow (red curve) is a good indicator of productivity changes due to intervention efforts, because it removes the effects of choked-back production caused by surface equipment limitations. The normalized curve shows the large and immediate impact of multiple acid treatments (indicated by blue circles) and the subsequent loss in well productivity within one to three months afterwards—indicating recurring scale precipitation.} \]
Gullfaks field before and after stimulation, engineers used NODAL analysis to determine the change in formation damage, called skin. Then, the effect of each acid treatment on different types of scale in each well was modeled using a coupled wellbore-reservoir simulator (see “Chemical Placement Simulator,” page 40). The impact of scale removal on the skin in each case was compared with the production-derived changes in skin to evaluate the type of scale and its location. The field study confirmed that carbonate reprecipitation in the gravel packs was the primary damage mechanism causing recurring production losses in the wells.

Chemicals that dissolve and chelate calcium carbonate can break this reprecipitation cycle. Ethylenediaminetetraacetic acid (EDTA) was an early candidate to answer the need for improved chemical removal, and is still used today in many forms (below). While EDTA treatments are more expensive and slower than hydrochloric acid, they work well on deposits that require a chemical approach. EDTA and variations on its chemical structure are also effective in noncarbonate scale removal, and show promise for the removal of calcium sulfate and mixtures of calcium-barium sulfate.

Recently, Schlumberger developed an improved EDTA-based scale dissolver, called U105, as a cost-effective alternative for carbonate matrix stimulation. This dissolver was designed specifically for calcium carbonate, but is also effective against iron carbonate and iron oxide scales. It dissolves carbonates more slowly than hydrochloric acid and has a higher dissolving capacity than traditional organic acids, such as formic and acetic acid. Once the scale is dissolved through chelation, there is no reprecipitation. Stable at temperatures up to 250°C [482°F], it is a low-toxicity scale dissolver that is effectively noncorrosive on most steels—making the treatment extremely safe.

Other chelating agents have also been optimized especially for barium and strontium sulfate scale. For example, U104 is based on an EDTA dissolver containing chemical activators that enhance the rate of scale dissolution, and has proven effective on a wide variety of scales including calcium sulfate, calcium carbonate and mixed scales. In a typical applications these solutions are diluted with fresh water with a 6- to 24-hour soak period.
The effectiveness of this new dissolver was demonstrated on a North Sea well that had high skin damage due to scaling in the near-wellbore matrix and perforations. The scale type was identified as mixed barium sulfate and calcium carbonate. A U104 treatment was designed to bullhead, or pumped against pressure, into the formation to give an average radial displacement of 3 ft [1 m]. The treatment was overflushed with a tubing displacement of inhibited seawater, and the well was shut in for a total soak time of 18 hours, after which it was returned to production (previous page, top). Production increased 450 BOPD [72 m³/d] paying out all materials, pumping and lost production costs in 12 days.

Conventional mechanical methods—Mechanical solutions to remove scale deposits offer a wide array of tools and techniques applicable in wellbore tubulars and at the sandface (below). Like chemical techniques, most mechanical approaches have a limited range of applicability, so selecting the correct method depends on the well and the scale deposit. Mechanical approaches, though varied, are among the most successful methods of scale removal in tubulars.

One of the earliest scale-removal methods was an outgrowth of the use of explosives to rattle pipe and break off brittle scale. Explosives provided high-energy impact loads that could remove scale, but often damaged tubulars and cement. Taming the explosive meant changing the type of explosive or reducing the amount of explosive load. A strand or two of the detonation cord, called a string shot, was found to be adequate.

String shots are still used today, especially as a simple diagnostic tool, when quick wireline entry and detonation during flow yield clues about the type and location of scale. Experience shows that using a few strands of cord, detonated by an electronic cap, and long enough to cover the zone of interest, is effective in removing scale blockages in perforations and thin scale films inside tubulars.

Thick scales, especially those in tubulars, are often too strong for safe explosive removal and have too little porosity for effective chemical treatments in a reasonable time frame. For these deposits, removal usually requires techniques developed for drilling rock and milling steel. Impact bits and milling technology have been developed to run on coiled tubing inside tubulars using a variety of chipping bits and milling configurations. The downhole power source is typically a hydraulic motor or a hammer-type impact tool. Motors are fluid-powered, stator and rotor combinations that turn the bit. Their power depends on fluid supply rate and motor size—smaller motors that remove scale inside tubing, typically ½-in. to 1½-in. diameter, provide torque from 100 to 130 ft-lbf.

Because scale is rarely deposited evenly on the tubing wall, milling power requirements vary enormously. When motors cannot supply the power needed for the bit to cut the scale, the motor stalls and the milling process stops. As a result, scale-removal rates vary with the type of scale and application, but generally range from about 5 to over 30 linear feet [1.5 to over 9 m] of scale removed from the tubular per hour of milling. The variation in milling speed depends on the match between the type of deposit and the combination of motor and mill. Experience shows that small, low-torque motors are generally more effective when run with small-tooth mills. Larger tooth mills, though more aggressive, do not spin well on irregular scale surfaces—stalling small motors. Thus, the small-tooth, less aggressive mills cut faster because they are less prone to frequent motor stalls.

### Tool Description

<table>
<thead>
<tr>
<th>Tool</th>
<th>Description</th>
<th>Clean hard bridges</th>
<th>Clean tubular jewelry</th>
<th>Other advantages</th>
<th>Other disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive displacement motor and mill</td>
<td>Fluid-powered Moineau motor and mill. Mill removes deposits by grinding.</td>
<td>Yes. Clean rate may be very slow.</td>
<td>Positive surface indication of cleaning Small cuttings make hole cleaning easier</td>
<td>Motor stator and mill are expensive expendables ~300°F [150°C] limit Not compatible with scale dissolvers Mill can damage tubulars</td>
<td></td>
</tr>
<tr>
<td>Impact hammer</td>
<td>Fluid powered percussion hammer. High shock forces shatter brittle deposits.</td>
<td>Yes. Clean rate may be very slow.</td>
<td>Positive surface indication of cleaning Simple, robust tool</td>
<td>Large cuttings size makes hole cleaning more difficult Not compatible with scale dissolvers</td>
<td></td>
</tr>
</tbody>
</table>

### Chemical cleaning

<table>
<thead>
<tr>
<th>Tool</th>
<th>Description</th>
<th>Clean hard bridges</th>
<th>Clean tubular jewelry</th>
<th>Other advantages</th>
<th>Other disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed wash tool</td>
<td>Fixed tool with many large diameter nozzles. Normally used only with chemical dissolvers.</td>
<td>Yes, if deposit is soluble.</td>
<td>Simple, robust tool</td>
<td>Most fluid power lost to circulating friction Low nozzle pressure—cannot remove inert deposits</td>
<td></td>
</tr>
<tr>
<td>Spinning-jetting tool</td>
<td>Rotational torque provided by nozzles offset from tool axis. No speed control.</td>
<td>Yes, if deposit is soluble.</td>
<td>Simple tool Complete wellbore coverage by rotating jets</td>
<td>Inefficient jetting due to high rpm (&gt;3000)</td>
<td></td>
</tr>
<tr>
<td>Indexed-jetting tool</td>
<td>Nozzle head rotates ~90° when coiled tubing pressure is cycled. Head has many small-diameter nozzles to improve wellbore coverage.</td>
<td>Yes, if deposit is soluble.</td>
<td></td>
<td>Requires multiple cleaning runs increasing job time and coiled tubing fatigue No surface indication of cleaning Small cleaning radius due to small nozzles</td>
<td></td>
</tr>
<tr>
<td>Turbine-powered jetting tool</td>
<td>Fluid turbine rotates nozzle with two nozzles. Eddy current brake controls rpm.</td>
<td>Complete wellbore coverage with large cleaning ratios Abrasives cannot be pumped through turbine Complex tool</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sonic tools</td>
<td>Used to create high-frequency pressure pulses that remove deposits by shock waves or caviation.</td>
<td>Yes, if deposit is soluble.</td>
<td>Simple</td>
<td>Hydrostatic pressure suppresses cavitation Tools not effective in removing hard scales in lab tests</td>
<td></td>
</tr>
</tbody>
</table>

### Jet Blaster tools

<table>
<thead>
<tr>
<th>Tool</th>
<th>Description</th>
<th>Clean hard bridges</th>
<th>Clean tubular jewelry</th>
<th>Other advantages</th>
<th>Other disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scale Blasting technique</td>
<td>Nozzle head rotated by two nozzles offset from tool axis. Viscous brake controls rpm.</td>
<td>Complete wellbore coverage with large cleaning radius Positive surface indication of cleaning</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bridge Blasting technique</td>
<td>Fluid-powered ‘Moineau’ motor and jet/mill head. Radial jets follow pilot mill.</td>
<td>Positive surface indication of cleaning</td>
<td>Motor strator is an expensive expendable ~300°F limit</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Impact tools, such as the Baker Oil Tools Hipp Tripper tool, are reciprocating tools that work much like a small jackhammer with a rotating bit. They impact the scale at 300 to 600 times per minute and rotate about 20 times per minute, typically with a chisel or star-shaped bit. Mills cannot be used with such tools because the impacts cause excessive damage to the mill surface. These tools work best on brittle scale deposits, removing scale as quickly as 10 to 100 linear feet [3 to 30 m] per hour.

When fullbore access to scale deposits is partially blocked by physical restrictions such as decreasing tubing diameter and encroaching completion equipment, tools that can change diameter are required to remove scale below the restriction. If such equipment is not available, then a small hole—less than full tubing size—can usually be drilled through the scale below the restriction to allow increased flow. Nevertheless, a residual scale surface in the tubing encourages new scale growth and makes inhibitor treatments to block nucleation much more difficult. A clean, bare steel surface is more effective in preventing new scale growth.

Impact tools like motors and mills usually need fullbore access and seldom clean scale completely to the steel walls. For such partial access situations, under-reaming mills can increase the effective diameter by moving the milling blades outward in response to pump pressure and rate. Under-reaming mills are effective, but remove scale only at about half the rate of a typical mill.

Fluid-mechanical jetting methods—Downhole fluid-jetting systems, such as Halliburton’s Hydroblast and BJ-NOWSCO’s RotoJet system, have been available for many years to remove scales in production tubing and perforations. Such tools use multiple jet orifices or an indexed jetting head to achieve full wellbore coverage. These tools can be used with chemical washes to attack soluble deposits wherever placement is critical to prevent bulkheading reagent losses. Water jetting can be effective on soft scale, such as halite, and debris or fill, but experience shows that it is less effective on some forms of medium to hard scale such as calcite and barium sulfate (left).

Water-jetting methods—Removing calcium carbonate scale with water jetting. The tubing was jetted with a single water jet at a rate of 2.4 in./min [1 mm/sec]. Although carbonate scale has been removed, a considerable amount remains in place.

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At surface pressure, water jetting removes scale by cavitation, whereby small bubbles form in the fluid jet stream. These bubbles are created by the large pressure release as fluid passes through the jet nozzle. The bubbles collapse on impact with scale, causing a forceful—almost explosive—erosive effect. Research at Schlumberger Cambridge Research, England, shows that this cavitation process is highly suppressed downhole under hydrostatic borehole pressure. Cutting rates are typically reduced by a factor of four or more. Surface pumping-pressure limitations using coiled tubing-conveyed jetting tools prevent increasing fluid pressure high enough to overcome the differential loss at the bottom.

**Abrasive slurries**—Adding a small concentration of solids, 1% to 5% by weight, to a water jet can drastically improve its ability to cut through scale. Water jets using abrasive sand are widely used in the construction and demolition industries for cutting reinforced concrete, and even in demilitarization for cutting live ammunition without generating heat or an ignition source. This technique also shows superior cutting performance in calcium carbonate scale over water jetting alone (previous page, top right). Unfortunately, using abrasives such as sand can damage steel tubulars. When scale is completely removed from tubing, the abrasive jet erodes the steel as efficiently as it does the scale. Should the jetting tool stall, there is a significant risk of the abrasive jet perforating the steel tubing.

An abrasive jet that cuts scale without damaging tubing must exploit the difference in hardness between wellbore scale and the underlying steel. One of the key differences between wellbore scale and tubular steel is that while scale is brittle, steel is prone to ductile failure (previous page, bottom). A sharp sand particle will erode the surface of ductile material by a cutting and plowing action. On the other hand, a hard round particle will bounce off the surface of ductile material, removing only a small volume of steel and leaving an impact crater. Scale exhibits brittle failure, so the impact of a hard particle fractures the scale and ultimately causes substrate disintegration. Scale breakdown is independent of particle shape.

Choosing round rather than sharp, angular particles promotes scale erosion while reducing damage to steel tubulars. For example, Adams Coiled Tubing provides a glass-bead abrasive jetting system. The jetting tool has eight stationary nozzles allowing complete radial coverage and downward pointing jets. The system is compatible with foaming fluids and effective on all types of scale. On the other hand, the craters formed by repeated impacts with glass particles can eventually lead to fatigue and failure of the steel surface (above).

**Sterling Beads abrasives**—Glass beads are significantly harder than the steel tubing and cause excessive tubing erosion. Reducing the hardness of the abrasive particles too much, however, renders them ineffective. Thus, the desired hardness is a compromise between minimizing damage to the steel while maximizing the scale-cutting performance. Other parameters, such as abrasive material friability, are also important. Although many spherical particles of correct hardness are available, they tend to have low durability and shatter on impact—imparting insufficient destructive energy to the substrate to remove the scale.

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Chemical Placement Simulator

A simulator can help design an effective chemical treatment. For example, StimCADE software is a coupled wellbore and reservoir stimulation program that includes a wellbore model, a reservoir model and a chemical reaction model for scale prediction. Input parameters include a comprehensive list of wellbore, formation, fluids and chemical treatment descriptions. The wellbore model solves convection-diffusion equations for fluid flow down the treatment string (production tubing, coiled tubing or the casing) to estimate friction pressure during pumping.

In estimating the invasion of treatment fluids into the formation surrounding the wellbore, the reservoir model tracks the location of different fluid fronts in the reservoir. The chemical reaction model estimates the rate of mineral dissolution following kinetic rate laws for the solvents used and mineral species present in the formation lithology section. The net mineral dissolution is translated into a skin reduction for each acid treatment.

Additional features include the ability to model wellbore deviation, predict effects of diverting agents on fluid-invasion profiles in the reservoir, and simulate flow of two fluids simultaneously into the well—one down tubing or coiled tubing, and one down the annulus. These features help predict the efficiency of various treatment placements.

Universal scale-removal system—Engineers at the Schlumberger Reservoir Completions Center in Rosharon, Texas, USA, developed a viscous fluid-controlled rotating head jetting tool called the Jet Blaster tool, that has jet-nozzle characteristics optimized for use with Sterling Beads abrasives (right). This new rotating jetting-head-based tool, combined with the Sterling Beads abrasives, forms the basis of a new system of coiled tubing-conveyed intervention services designed to remove scale in downhole tubulars. The Blaster Services system features three scale-removal techniques that can be applied to a wide range of scale problems:

• The Scale Blasting technique combines the use of Sterling Beads abrasive with the new jetting tool for hard-scale removal.
• The Bridge Blasting technique uses a powered milling head and abrasive jetting, when scale completely plugs the tubular.
• The Jet Blasting technique uses the new jetting tool with nonabrasive fluids for soft-scale-removal applications.

The scale-removal system also includes a scale-removal design program, called Jet Advisor software, that enables an operator to optimize the jetting-tool configuration and nozzle size based on well conditions to maximize jetting power and head penetration rate. It also helps with the selection of either abrasive or nonabrasive—fluid only—scale-removal techniques. The Jet Advisor program alerts the operator to the risk of tubular damage due to headstalls—using steel damage and coiled tubing stick-slip analysis.

Jet Blaster tool. Photograph (top) shows the toolbox containing the abrasive jetting system as delivered to the wellsite. The Jet Blaster downhole tool (middle left) includes coiled tubing connections, check valves and disconnect equipment; dual-acting circulation unit; and a filter that prevents unexpected debris in the jetting fluid from clogging the jetting nozzles. The tool converts fluid power to a continuous speed rotation with a viscous shearing-fluid speed-controlled swivel for removing scale along the inside of tubular walls (insert middle right). Reaction forces from the two offset jet nozzles provide about 5 ft-lbf torque to rotate the swivel head at speeds less than 200 rpm. The jetting head consists of a nozzle carrier and a drift ring. In the Jet Blasting and Scale Blasting techniques, the nozzle carrier is assembled with two opposing tangential jets (bottom left). The offset jetting nozzles maximize hydrodynamic energy transport to the wellbore. The drift ring allows weight to be set down on the tool so that the tool will advance only after the entire minimum bore diameter is cleaned. In the Bridge Blasting technique, a positive displacement “Moineau” style motor (bottom center and right) can be used to drill scale bridges across tubing for Bridge Blasting applications. This motor can deliver 150 ft-lbf torque to the head module at 300 rpm.
Removing hard scale—For hard scales like iron, strontium and barium sulfate, nonabrasive fluid jetting and chemical treatments are inadequate. The controlled-erosive action of the Sterling Beads abrasive has been successful in removing every type of scale in tubing, including the most difficult barium sulfate scales, at rates up to 100 ft/hr [30 m/hr] or more. The Scale Blasting technique is a particularly good option when the scale encountered in the well is insoluble, unknown or of variable hardness. The system also provides a safe method to remove scale from downhole completion equipment. Rate of penetration (ROP) is controlled using a drift ring that ensures full tubing-diameter cleaning with minimum damage to the steel surface.

The Scale Blasting technique was used in the North Sea to remove hard barium sulfate deposits on two gas-lift valves, identified by multifinger caliper logs, in a multiple-mandrel gas-lift completion well (right). Well flowing pressure decreased as water was injected, and there was a possibility that the available gas pressure would be inadequate to reach the only remaining active valve in a side-pocket mandrel. Failure to remove and change a second damaged valve would have resulted in the well dying as water cut increased and led to a costly workover. Solvents were ineffective in removing enough scale to allow kickover tools to engage and latch onto the valves.10

The new coiled tubing-conveyed abrasive-jetting technology was used in this well for the first time in the North Sea. Jet Advisor software provided the optimal drift ring size, nozzle and nozzle-head size to efficiently clean the hard scale. The software also provided the optimal abrasive concentration and predicted scale-removal rates. First, the damaged side-pocket mandrel was cleaned at a rate of 100 ft/hr [0.5 m/min]. Then, the other operating side-pocket mandrel was cleaned with the same procedures. The entire operation was evaluated by running the kickover tool and checking the possibility of changing the gas-lift valves in the cleaned side-pocket mandrels. A gamma ray log was also run to evaluate the remaining scale deposit in the completion (right). The damaged valve was successfully retrieved and replaced. Abrasive jetting efficiently cleaned the scale without damaging the mandrel.

In another example, up to 0.38-in. [1-cm] thick barium sulfates prevented an operator in Gabon, West Africa, from accessing and changing five gas-lift mandrels in a well with a tapered production-tubing completion. The well had not produced since 1994. Gauge cutter runs showed scale buildup bridged the tubing, blocking access to the lower section of the well. The workover objectives were to clean the tubing scale, change out gas-lift mandrels, and gain access to the well below the tubing.

Early attempts at conventional scale-removal methods, including several positive displacement motors (PDM) and milling runs, an impact hammer and another jetting system following dissolver treatments, were unsuccessful. The ability to remove hard barium sulfate scale under a wide range of conditions made the Scale Blasting technique an attractive alternative. Because of the tapered completion, several sizes of gauge rings and nozzle heads were required. The jetting fluid was formulated with standard concentrations of polymer and Sterling Beads abrasives to achieve optimum well cleanup and rate of penetration.


Jet Advisor software optimized the rotating jetting-head torque and abrasive cutting efficiency with rate, pressure and viscosity as variables in the 56°-deviated wellbore. The most effective pump rates and surface pressures were determined by the CoilCADE software, while the CoilILIMIT program was used to determine the safe working limits of the coiled tubing.

The treatment resulted in 6500 ft [1981 m] of tubing cleaned in a total jetting time of 25.5 hours. Average penetration rates were 600 to 900 ft/hr [3 to 5 m/min] in 3½-in. tubing, and 40 to 100 ft/hr [0.2 to 0.5 m/min] across the gas-lift mandrels and in the 2½-in. tubing. Successful treatments allowed the operator to replace the gas-lift mandrels, and the well now produces 2000 B/D [320 m3/d]. The removed gas-lift mandrels had been cleaned in all areas exposed to the wellbore and the valves were not damaged.

Removing scale bridges from tubulars—
Scale deposits that completely bridge tubulars can be removed with a special adaptation of the Jet Blaster abrasive jetting tool using the Bridge Blasting technique. The Bridge Blasting technique incorporates a 1.68-in. diameter PDM specially modified to prevent Sterling Beads abrasive from clogging the motor’s high-pressure labyrinth shaft seal. The PDM drives a combination jetting and milling head that uses a Reed-Hycalog diamond mill to make a small pilot hole in the deposit (above right). Radial jets complete the cleaning. Since the mill removes only a fraction of the total bridged deposit volume, the cleaning rate and overall mill and motor reliability are much higher than with conventional PDM-milling-cleaning methods.

A drift ring centers the tool and prevents mill damage to the tubulars—frequently a problem with conventional milling techniques. In hard, bridged deposits, a different jet-drilling head is used if the pilot mill does not achieve acceptable cleaning rates. The jet-drilling head uses four critically oriented jetting nozzles to drill through the scale bridge using a Sterling Beads slurry. A subsequent run with the Jet Blaster swivel with Sterling Beads abrasive is usually required to complete cleaning to the full diameter of the tubulars.

Iron sulfide [FeS₂] scale is a special problem for BP Amoco throughout the Kaybob south field in the Beaverhill Lake formation in Canada. The iron sulfate crystallites form directly on steel tubing, attaching firmly, and remain either bimetallic or crevice corrosion beneath the crystallites. These sulfur gas [H₂S] condensate wells deposit high molecular-weight compounds, such as asphaltene, on the iron sulfide crystallites inside tubing.11

This unusual scale cannot be removed by hydrochloric acid, surfactants or chelating agents because asphaltene protects the scale from chemical solvents. The scale can be removed only by mechanical techniques or by first chemically removing the asphaltene layers. Past experience with conventional methods for scale removal—including foamed acid, acid jetting combined with organic solvents such as xylene, and drilling, milling and tubing shakers—were inconsistent.

New abrasive jetting techniques using the Jet Blasting technique, and wellbore restrictions. Overall, 10,400 ft [3170 m] of scale were successfully removed from the eight wells in 32.5 hours cumulative jetting time.

Removing sand plugs—When wellbore deposits are soft, acid soluble or chemically reactive, the nonabrasive Jet Blasting technique is the most cost-effective and efficient. The increased fluid-jet efficiency from the optimized jetting head maximizes cleaning ability on soft scale, fresh cement and filter cake. Other drilling damage and insoluble deposits benefit greatly from a combined chemical and jet-cleaning treatment.

An operator in south Texas was having difficulty removing sand plugs in a well with three fracture-stimulated zones that were isolated by sand plugs. Each sand plug was topped with a cap

<table>
<thead>
<tr>
<th>Well</th>
<th>Blaster Services</th>
<th>Treatment time, hr</th>
<th>Length of scale removed, m</th>
<th>Tool drift O.D., mm</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well 1</td>
<td>Scale Blasting technique</td>
<td>1.5</td>
<td>1023</td>
<td>54</td>
</tr>
<tr>
<td>Well 2</td>
<td>Scale Blasting technique</td>
<td>1</td>
<td>45</td>
<td>46.7</td>
</tr>
<tr>
<td>Well 3</td>
<td>Bridge Blasting technique</td>
<td>13</td>
<td>162</td>
<td>46.7</td>
</tr>
<tr>
<td>Well 4</td>
<td>Scale Blasting technique</td>
<td>4</td>
<td>1108</td>
<td>46.7</td>
</tr>
<tr>
<td>Well 5</td>
<td>Scale Blasting technique</td>
<td>2.5</td>
<td>28</td>
<td>54</td>
</tr>
<tr>
<td>Well 6</td>
<td>Bridge Blasting technique</td>
<td>7</td>
<td>270</td>
<td>54/45</td>
</tr>
<tr>
<td>Well 7</td>
<td>Scale Blasting technique</td>
<td>2</td>
<td>511</td>
<td>54</td>
</tr>
<tr>
<td>Well 8</td>
<td>Scale Blasting technique</td>
<td>1.5</td>
<td>20</td>
<td>46.7</td>
</tr>
</tbody>
</table>


^Bridge Blaster milling head. The Bridge Blaster system can be configured with a radial jetting head, drift ring and a Reed-Hycalog mill (left), or with downward-facing abrasive jetting nozzles (right) that drill a hole through scale bridges that cannot be cut with tungsten carbide mills.

^Beaverhill Lake scale-removal results.
of silica flour to provide a better pressure seal. A drill motor with a mill was used to try to clean out the sand plugs. The first plug was cleaned out successfully, but the mill was completely worn down after cleaning 2 ft [0.6 m] of the second plug. A second mill managed to drill out only an additional 5 ft [1.5 m] in the plug before it was completely worn (above). The plug with silica flour on top had been crushed and packed tightly due to fracturing pressure from above, forming a hard fill.

Jet Advisor software was used to select the proper nozzle size for the Jet Blasting technique based on well conditions. Head components and sizes were based on well completion and fill material. The jetting fluid was a 2% potassium chloride [KCl] water with friction reducer, foaming agent and nitrogen [N₂]. Treatment resulted in a cleanout rate of 420 to 600 ft/hr [2 to 3 m/min]. The plugs and silica flour were removed from the well in less than one day, saving the operator the cost of the workover rig and five days in lost production.

Preventing Scale
The direct cost of removing scale from one well can be as high as $2.5M, and the cost of deferred production even higher. Just as prevention is better than cure in medical practice, keeping producing wells healthy is ultimately the most efficient way to produce hydrocarbons. In most cases, scale prevention through chemical inhibition is the preferred method of maintaining well productivity. Inhibition techniques can range from basic dilution methods, to the most advanced and cost-effective methods of threshold scale inhibitors.

Dilution is commonly employed for controlling halite precipitation in high-salinity wells. Dilution reduces saturation in the wellbore by continuously delivering fresh water to the sandface, and is the simplest technique to prevent scale formation in production tubing. It requires installation of what is called a macaroni string through the production tubing (above). The macaroni string is typically small-diameter tubing—less than 1/8-in.

In addition to dilution, there are literally thousands of scale inhibitors for diverse applications ranging from heating boilers to oil wells. Most of these chemicals block the growth of the scale particles by “poisoning” the growth of scale nuclei. A few chemicals chelate or tie up the reactants in a soluble form. Both approaches can be effective, but each requires careful application as treatments show little tolerance for change in the producing system. Chelating inhibitors block precipitation or scale growth only for a certain limited level of oversaturation. Equilibrium upsets occur, even in protected systems, allowing scale to precipitate. Because chelating agents consume scale ions in stoichiometric ratios, the efficiency and cost-effectiveness of chelants as scale inhibitors are poor.

In contrast, threshold scale inhibitors interact chemically with crystal nucleation sites and substantially reduce crystal growth rates. Threshold scale inhibitors effectively inhibit formation of mineral scales at concentrations on the order of 1000 times less than a balanced stoichiometric ratio. This considerably reduces the treatment cost. Most scale inhibitors are phosphate compounds: inorganic polyphosphates, organic phosphate esters, organic phosphonates, organic aminophosphates and organic polymers. These chemicals minimize scale deposition through a combination of crystal dispersion and scale stabilization (left).
Inhibitor lifetime—Scale inhibitors are retained in the formation by either adsorbing to the pore walls or precipitating in the pore space. Adsorption is most effective in sandstone formations [above]. Treatment lifetimes depend primarily on the surface chemistry, the temperature, and the pH of the liquid contacting the formation, and are occasionally unusually short (3 to 6 months) because the adsorption capacity of reservoir rocks under reservoir conditions is limited. Under special conditions, such as high adsorption-capacity formations and low water-production rates, up to two-year lifetimes can occur.

Normally, treatment lifetimes exceed one year for properly designed treatments in which precipitation is the inhibitor retention mechanism—even when high water-production rates are encountered. For example, phosphates and phosphino-carboxylic acid inhibitors are among those known to prevent calcium carbonate scale. Calcium ions are often liberated when the inhibitors are placed in carbonate formations, and precipitation is the dominant long-term retention mechanism in carbonate formations. A calcium chloride brine overflush is often pumped to induce scale inhibitor precipitation and extend the treatment lifetime in reservoirs that do not naturally contain enough soluble calcium to precipitate the inhibitor.

Long inhibitor lifetime can be also be achieved by pumping large volumes of inhibitor deep into the formation, such that the inhibitor is exposed to and absorbed to a large surface area. This is not always successful because squeezing water-based inhibitors into oil zones can lead to a temporary change in formation wettability. This results in unacceptably long production-recovery times. Alternative oil-soluble inhibitors that do not cause the formation rock to become water wet are needed. New fluids based on critical point wetting of rock are being tested for inhibitor enhancement. These make the reservoir rock “super wet,” allowing a higher degree of inhibitor retention and a longer protection lifetime.

Commercial software, such as the Squeeze-V program that was developed at Heriot-Watt University, Edinburgh, Scotland, models the retention and release of scale inhibitors by adsorption or precipitation. This program is used to optimize inhibitor concentrations, treatment and overflush volumes to maximize inhibitor lifetime. It can also be used to match histories of previous treatments as part of an overall strategy of continual improvement in scale management.

Improving inhibitor placement—Ultimately, treatment performance is based on scale prevention, not on the duration of the inhibitor. Proper inhibitor placement is a key factor in the performance of an inhibitor squeeze treatment. Bullheading the inhibitor into a formation can lead to overtreatment of low-pressure and high-permeability zones, and undertreatment of high-pressure and low-permeability zones. Thus, it is considered good practice to place scale inhibitors in heterogeneous formations using the same placement techniques employed to control acid placement. In fact, there are significant advantages to combining the acid and scale-inhibitor treatments to ensure that the scale inhibitor is controlled along with the acid. Care must be taken to insure that the acid pH does not exceed that required for inhibitor precipitation.

Integrating scale inhibitor with fracture stimulation—Protection of propped fractures against mineral scale fouling is critically dependent upon proper inhibitor placement. Portions of the fracture that are left untreated by the inhibitor might be irreversibly damaged because of the ineffectiveness of contacting mineral scales in proppant packs with scale solvents. As a result, there have been efforts to pump scale inhibitors in fracturing fluid, thereby guaranteeing proppant-pack coverage.

Fracture stimulation with inhibitor placement. High-efficiency scale-inhibitor placement is achieved by pumping the inhibitor into the fracturing fluid during fracture stimulation. The inhibitor is retained by adsorption on the formation in the leakoff zone, or by precipitation on the proppant. As formation water passes through the inhibitor-absorbed zone, it dissolves enough inhibitor to prevent the water from precipitating in the fractures and wellbore.
An alternative inhibitor delivery system, implemented by Schlumberger, called the ScaleFRAC system combines a scale-inhibitor treatment and fracture treatment into a single-step process by using a new liquid inhibitor compatible with fracturing fluids. The scale inhibitor is effectively placed everywhere in the propped fracture by pumping the scale inhibitor during the pad and sand-laden stages of the fracturing treatment (previous page, bottom). The new process eliminates a scale squeeze treatment immediately following a fracture stimulation treatment, and also circumvents the problem of slow oil-production recovery caused by wettability changes produced by conventional scale-squeeze treatments.

The new inhibitor delivery system has been used extensively on the North Slope in Alaska, and has found applications in the North Sea and the Permian Basin. For example, results in the Permian Basin show that inhibitor concentrations in produced water remain above threshold values necessary to prevent scale deposition significantly longer than conventional treatments (above right). The new integrated inhibitor-fracture treatment provides sustained fracture productivity due to better inhibitor placement. It also simplifies wellsite logistics, due to combining the squeeze and inhibitor treatments; and the well returns to production faster because there is no shut-in to allow the inhibitor to adsorb or precipitate in the formation.

Recently, AEA Technology in England developed a new porous ceramic proppant that is impregnated by the scale inhibitor for use during hydraulic fracturing. The novel feature of the AEA scale inhibitor is that the salt of a commonly used oilfield scale inhibitor is precipitated such that it fills the porosity of a lightweight ceramic proppant. The filled ceramic proppant can then be substituted for a fraction of the original proppant in the fracture-treatment design. Upon production, any water flowing over the surface of the impregnated proppant will cause dissolution of the scale inhibitor—protecting the well against scale depositing from the water. The inhibitor-release mechanism is dissolution of the inhibitor from the interstitial pores of individual proppant grains. This avoids wasted inhibitor by phase trapping. After all the inhibitor is dissolved, the ceramic substrate remains and continues to serve as a propping agent.

Conclusion

There have been many significant advances in scale control and remediation in recent years. Today, operators have access to a portfolio of chemical and mechanical products designed to remove scale and prevent its buildup. The improvements in placement technology, reservoir chemistry and intelligent fluids furnish more cost-effective options for chemical scale inhibition and removal in the formation. Developments in scale-removal services incorporating new abrasive materials are providing fast, reliable ways to remove scale inside tubulars without risk to the steel tubing.

Each new technology improves one aspect of scale control in a wellbore. Combined, these new technologies become part of a scale-management process in which one can apply surveillance methods to identify the onset of scaling conditions and develop the optimum strategy for reducing scaling-related production losses and remedial expenses. The strategy may include elements of scale prevention and periodic removal. Engineers working in scale-prone reservoirs are grateful for every improvement in the technology used to combat their scale problems.  

—RCH
In any enterprise in which people do the work, efficiency and productivity depend on human factors. Health and safety of workers and protection of the environment are cornerstones of most modern business policies. By establishing and complying with health, safety and environment (HSE) principles, companies can attract qualified personnel, fulfill government requirements, assure business longevity and ultimately be more productive.

But to excel in an industry, meeting minimum HSE standards is not enough. While HSE programs still come first, high-performance companies are learning that taking standards of employee and environmental well-being to a higher level yields even higher levels of performance.

The key to this achievement is the application of principles of ergonomics to the daily tasks that workers face. Derived from the Greek words "ergon" for work and "nomos" for natural laws, ergonomics is the study of the efficiency of people in their working environment. The main tenet of this field of study is that the working environment should be adapted to the worker’s needs.

Applying this theory to the oil and gas industry potentially means addressing a wide range of activities, from handling heavy equipment to sitting down and picking up the telephone. Conditions can span arctic cold, desert heat, heavy seas and choking dust, and include situations that are tense, dangerous, physically demanding, repetitive and dull. Clearly, not all aspects of the work environment can be modified to suit the individual. However, approaching each task with the view to optimizing it for the worker builds efficiency into every operation.

This article explains the basic principles of ergonomics and shows how their application increases safety and productivity. Following that is a practical illustration of these techniques in a project to optimize aspects of marine seismic acquisition, vessel design and training simulation for the new vessel, Geco Eagle.

Optimizing Work Environments
One of the fundamental fallacies of the world of work is that people can adapt to anything. To a point, people can adapt to a new way of thinking, an unaccustomed activity or an uncomfortable posture. The degree to which the adaptation succeeds depends on many factors, such as the ability of the person, the effort involved, the duration, and the level of discomfort, difficulty or danger in the new activity.

Some common working conditions are not regarded as dangerous enough to warrant safety precautions, but are still important to consider, such as noise levels, lighting, vibrations, temperature, boredom, work posture and repetitive actions. These can potentially result in permanent hearing loss, eye strain, fatigue, loss of concentration and mistakes. In addition to contributing to lower productivity, the latter two especially—work posture and repetitive actions—are now recognized as responsible for more enduring bodily harm.
Repetitive actions and poor posture have been identified as the causes of repetitive strain injury, or RSI, in the medical field. The simple actions of standing, sitting or moving improperly can lead to permanent muscular and skeletal damage (below).

Application of ergonomic principles can help in the design of work environments that prevent harmful posture and actions. For office work, properly designed chairs, desks, computer keyboards and office spaces reduce strain and produce improved health and satisfaction for staff and customers, less discomfort and increased productivity and performance. These in turn lead to fewer accidents, less sick leave, lower staff turnover and less retraining for replacement staff. And suitably formulated equipment for field work delivers similar benefits.

Along with ergonomic considerations, equipment requirements in most work environments benefit from attention to technical efficiency and safety, manufacturability and disposal. The optimal product-design process reconciles these through a series of five steps:

**Review**—The human and technical factors that will influence the success of the final project are investigated.

<table>
<thead>
<tr>
<th>Action or Posture</th>
<th>Resulting Injury</th>
</tr>
</thead>
<tbody>
<tr>
<td>Standing in one place</td>
<td>Feet and legs, varicose veins</td>
</tr>
<tr>
<td>Sitting erect without back support</td>
<td>Strained extensor muscles of the back</td>
</tr>
<tr>
<td>Seat too high</td>
<td>Strained knees, calves and feet</td>
</tr>
<tr>
<td>Seat too low</td>
<td>Strained neck and shoulders</td>
</tr>
<tr>
<td>Trunk curved forward when sitting or standing</td>
<td>Damage to lumbar region, intervertebral discs</td>
</tr>
<tr>
<td>Arm outstretched sideways, forwards or upwards</td>
<td>Shoulder and upper arm, periarthritis</td>
</tr>
<tr>
<td>Head excessively inclined backwards or forwards</td>
<td>Neck, deterioration of intervertebral discs</td>
</tr>
<tr>
<td>Unnatural grasp of hand grip or tools</td>
<td>Forearm, deterioration of tendons</td>
</tr>
</tbody>
</table>

**Observe**—Human-factors issues are observed in a working context with existing equipment and documented to identify opportunities for innovation.

**Visualize**—A future direction is conceived with creative design concepts through brainstorming, sketches and mock-ups.

**Evaluate**—The feasibility of various solutions is tested to converge on an optimal direction using computer-aided design (CAD) visualization, solids modeling and sometimes full-size test setups.

**Implement**—The engineering group responsible for manufacture is assisted to ensure that the most critical design aspects are preserved.

In addition to considering ergonomic aspects in the design of a product, the discipline of industrial design brings a balance of functionality and aesthetics. Other industries, such as the automotive industry, have long benefited from the recognition that customers want a combination of optimal mechanical performance, high reliability, personal comfort, good value and attractive appearance. The successful industrial design process blends function, ergonomics and a positive perceived image to yield a product differentiated from that of the competition.

Such a process for improving equipment and work environments and optimizing design has been developed by the Schlumberger Industrial Design group—a multidisciplinary team of graduate industrial designers, ergonomists and human factors specialists—working in Gatwick, England and Sugar Land, Texas, USA.

Originally a design resource for Schlumberger Resource Management Services, the team expanded its repertoire to offer industrial design and ergonomic resources to Oilfield Services starting in 1988. The Industrial Design group has worked with dedicated product-design teams on a wide range of products including automated test equipment, pay telephones, gasoline dispensers, utilities metering systems, control rooms on semisubmersible rigs, oilfield vehicles, hand-held and back-packable portable equipment, hardware and coiled tubing units.

1. For information on the Schlumberger Industrial Design group: [http://www.slb.com/qhse/design/](http://www.slb.com/qhse/design/)
The team has acquired considerable knowledge of general field operations through extended visits to both land and offshore locations. This knowledge base helps ensure that new projects are undertaken with a solid understanding of the working environment. The Industrial Design group sometimes tackles a problem without detailed prior knowledge of the specific product or service, unaware of standard practice. This can be a great advantage: by coming in with a fresh perspective and applying a structured approach, the group can open up creative design possibilities and deliver novel solutions that are unhindered by current practice and that promote efficiency, safety and quality. It was in this manner that the group entered upon its most recent project—optimizing the designs of the Geco Eagle back deck and instrument room for improved marine seismic data-acquisition efficiency (previous page, top).

Towing
Until the early 1980s, seismic vessels towed only one streamer. Since then, the number of streamers has gradually increased and now 6- or 8-streamer configurations are common, with some vessels achieving 10. Total spread, or distance between outermost streamers, has grown to 900 m [2950 ft], and typical streamer lengths have more than doubled from 3000 to 8000 m [9840 to 26,250 ft]. Anticipating continued growth in the marine seismic industry, Schlumberger projected a future demand for vessels that could tow up to 20 streamers.

Towing this larger mass of cable requires more powerful vessels with more room to store reeled streamers and extremely wide decks to facilitate streamer deployment. In the past, smaller, purpose-built seismic vessels were upgraded and fishing trawlers were converted to accommodate the added space and power requirements. However, neither of these proposals represents a cost-effective solution because they do not offer the new capacity sought—a survey footprint, or streamer length x spread, of more than 16 km² [6 sq miles], by the beginning of the 21st century.

Also, as vessels become larger and the number and separation of streamers grow, crews are challenged to deploy and operate more complex acquisition arrays involving large amounts of costly in-sea equipment. The potential hazards have never been greater.

These constraints led Schlumberger to opt for a new purpose-built vessel, and in doing so, to reevaluate the requirements of a new seismic acquisition platform equipped with state-of-the-art technology. The Geco Eagle would represent a leap not only in terms of her size—the world’s largest seismic acquisition vessel—but also in other fundamental aspects of design.

The back deck and the instrument room, the main centers of acquisition operations, were two areas targeted for ergonomic optimization. To identify problems, members of the Industrial Design group conducted a full study of current practice by visiting existing Schlumberger seismic vessels and observing operations. All activities and equipment were documented and photographed. This phase identified numerous opportunities for improvement.

Working Back
On the back deck, the main challenge is to deploy safely and efficiently the increased number of streamers called for in the new vessel design (left). On existing vessels, each streamer is reeled out and directed by hand-operated hydraulic controls located near the reel or by hand-held radio control. This requires an operator on the back deck for every streamer manipulation. It would be safer and more efficient if the streamers could be controlled remotely by one person from one central location.

Attaching equipment to each streamer can require stretching and leaning over the stern. The towpoint, or point where the streamer departs from the vessel and slopes toward the water, may be high overhead, and the connection maneuver can require significant upper body strength.

^ Back deck of the Geco Eagle.
Lost-time injuries in the marine seismic business. According to this 1998 study performed by the UK Offshore Operators Association (UKOOA), the majority of lost-time injuries occurs on the back deck. The study collated HSE statistics from all marine seismic contractors for all seismic vessels worldwide for the years 1993 though 1997.

### Lost-Time Injuries (LTI) by Work Area (1993-1997)

<table>
<thead>
<tr>
<th>Work Area</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Back Deck</td>
<td>51%</td>
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<tr>
<td>Open Deck</td>
<td>19%</td>
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<td>Small Boat</td>
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<td>Accommodation</td>
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<tr>
<td>Ashore</td>
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</tr>
<tr>
<td>Chaseboat</td>
<td>2%</td>
</tr>
<tr>
<td>Engine Room</td>
<td>2%</td>
</tr>
<tr>
<td>Compressor</td>
<td>1%</td>
</tr>
<tr>
<td>Accommodation</td>
<td>4%</td>
</tr>
<tr>
<td>Chaseboat</td>
<td>2%</td>
</tr>
<tr>
<td>Engine Room</td>
<td>2%</td>
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<tr>
<td>Compressor</td>
<td>1%</td>
</tr>
<tr>
<td>Other</td>
<td>1%</td>
</tr>
</tbody>
</table>

^Lost-time injuries in the marine seismic business. According to this 1998 study performed by the UK Offshore Operators Association (UKOOA), the majority of lost-time injuries occurs on the back deck. The study collated HSE statistics from all marine seismic contractors for all seismic vessels worldwide for the years 1993 though 1997.

^Back-deck crew handling streamer equipment at the stern of the vessel. Lifelines are an HSE requirement in this dangerous work environment.
The field studies identified several opportunities to improve back-deck working conditions that would lead to higher productivity and quality, and address particular safety concerns. Many lost-time injuries in the marine seismic business stem from inappropriate handling of equipment, and most occur on the back deck (previous page, top). Reducing the number of workers exposed to risk and the high level of exertion on the back deck will produce a more comfortable and productive work environment.

Not only is the work physically demanding, uncomfortable, wet and tiring, but it is also potentially dangerous. On some vessels, the back deck slopes down or drops off abruptly without any wall or guardrail. To control hazards in these working environments, workers are required to wear life vests and safety harnesses, or lifelines (previous page, bottom). However, lifelines can restrict movement to the point that they need to be unclipped to access out-of-reach equipment, and the crew may forget to reattach them. The redesign should address these issues, and allow the crew to work safely away from the back edge of the vessel with equipment at an appropriate level relative to body height.

Making practical design changes required analysis of all the tasks performed onboard. Following a one-week study on an operating vessel, task analysis techniques were used to document and analyze standard operating procedures on the back deck and to highlight areas of design opportunity (above). The task analysis also helped define design details and provided design-goal specifications for the streamer-control systems. Next, a conceptual design phase was launched to explore design opportunities. Early in the design program, three-dimensional solids ProEngineer CAD visualization techniques were
used to evaluate design concepts. Of particular benefit was the use of fly-through techniques to let the design team virtually move around a model of the back deck on screen, to check lines of sight, achieve optimum equipment positioning and to identify and assess safety issues (above).

The design team established that many back-deck problems were centered around the manipulation of streamers and the lack of clear working space arising from the large number of streamers crossing the work area. These problems stemmed from the way streamers were being handled between the storage reels deep within the vessel and the towpoint where they were deployed into the sea. A creative design program was initiated to see if it would be possible to redesign the streamer towpoints. Many solutions were examined through CAD solids modeling, leading to an innovative design that featured a traveling towpoint mounted on a rear pivoting beam (next page, top).\(^3\)

This allows the streamer to be above head-height while being towed during acquisition activities, but also permits it to be lowered and backed to a position nearly two meters \([6.5 \text{ ft}]\) away from the stern of the vessel, creating a safer work area (next page, bottom). The new design requires less upper-body strength and awkward strain to operate, letting female workers contribute more in areas previously the domain of their male colleagues.

In addition to providing a completely clear back deck when all streamers are deployed, the new design obviates the need for lifelines or harnesses. These are no longer specified as part of the HSE policy on the Geco Eagle streamer deck, making it more comfortable for workers to handle streamers as well as Monowing deflectors, buoys and other equipment.\(^4\)


\(^4\) The Monowing deflector applies aircraft-wing concepts to deflect streamers apart, thereby achieving wide streamer spreads without the assistance of additional vessels. The Monowing technique creates 40% less drag than traditional deflectors and currently enables streamer separations of up to 1400 m \([4590 \text{ ft}]\).
A crew member works in a safer area and a comfortable position. Hydraulically powered bars extend and contract to bring the towpoint within easy reach.

CAD modeling leading to new traveling towpoint design. In this rendition, a crew member in blue is standing near the streamer that has been brought down to the work area.
Other aspects of back-deck work were also transformed. In a sweeping change from traditional practice, Schlumberger proposed transferring streamer control from manual hydraulic functions at the individual reels to computer controls in a centrally located control room. The streamer-control station would house the control position, various control panels and monitors, and closed-circuit televisions (CCTV) (right).

CAD simulations helped position the streamer-control station itself and define its interior design and equipment configuration to ensure clear line-of-sight from the operator’s seated position to all critical areas of the back deck (below). Unobstructed lines of sight were validated by flying through the CAD model of the deck. Based on the fly-through tests, some of the columns supporting the upper deck were repositioned in the vessel design to improve visibility from the streamer-control operator’s viewpoint.

Task analysis of back-deck activities helped identify control requirements for all in-sea equipment, streamer reels and conveyors. Concepts were produced for controls, panel layouts and

^ Conceptual design of the streamer-control station. The climate-regulated room would house a seat with joy-stick controls, monitors, closed-circuit televisions (CCTV) and alarm lights.

^ A CAD-simulated view from the streamer-control room. These simulations helped position the room and its components to ensure primary visibility to the entire back deck and camera exposure to streamer winches behind the control room.
on-screen user interfaces. CAD simulations also helped evaluate placement of CCTV cameras that would monitor reel and streamer operations for display in the streamer-control station CCTV system. Emergency controls and alarm indicators were positioned close at hand in the primary field of vision.

The streamer-control station incorporates a Hitec Cyberbase chair—an ergonomically proportioned chair with joy-stick control grips to command streamer deployment (right). From here the streamer operator has the ability to control all in-sea equipment, streamer reels, conveyance systems and Monowing deflectors from one central point. Streamers can be deployed and recovered, controlled and tested.

The joy-stick user interface and multifunctional displays provide the means to interact with the massive spread of the Geco Eagle (below). This display from the TRINAV application, the onboard navigation processing software, shows outer streamers fully deployed and a few inner streamers unreeling. The joy-stick controls permit prompt response for quick adjustments to streamer position.

Creation of the streamer-control station meant that for the first time, rather than being exposed to the elements, the streamer operator could work in the comfort of a heated or air-conditioned room, making work safer and more efficient. The members of the crew were polled for their feedback on the new design features, and indicated that they wouldn’t want to go back to reeling streamers the old-fashioned way, without the control room.

Overall, the new back-deck design generated an enthusiastic response from the crew. They find the work safer, more comfortable and more efficient. According to Mick Richardson, vessel manager, the efficiency gained in easier and faster operations produces measurable savings. Time saved changing out used streamer sections, deploying and recovering tail-buoys and avoiding equipment tangles during streamer maintenance by smoothly controlling streamers, sums to 16 hours—the equivalent of $110,000—per month.

^ Streamer controller driving winches with joy-stick controls.

^ Concept for a TRINAV display from the streamer-control station. Streamer spools (left) can be monitored as streamers are deployed. The streamer-spread display (right) shows the vessel in the center of the screen and the full streamer spread towed behind. Some of the streamers in the center of the spread are not fully deployed. Tail-buoys are identified with individual colors.
**Up Front**

The instrument room also required modification to improve acquisition and onboard processing efficiency. The instrument room is where geophysicists monitor and quality-control data acquisition, navigators plan and monitor the vessel’s progress and observers watch operations. In addition to these standard operations, the *Geco Eagle* supports on-line onboard data processing activity. In the instrument room, many activities are performed concurrently, and clear communications are required for rapid decision-making.

The Industrial Design group had already produced a design of vessel instrument rooms for the *Geco Gem*-series of vessels, launched in the mid 1990s. The *Geco Eagle* benefitted from the experience of that exercise and adopted innovations tailored to her greater capacity.

In the earlier project, the problem-identification phase turned up areas for improvement. Each instrument room visited was a one-of-a-kind unstructured conglomeration of computers, monitors, instrument panels and controls (left). Equipment was not ergonomically positioned, communication between work posts was sometimes possible only by telephone, equipment was

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^ A vessel instrument room before redesign. Little thought was given to the arrangement of computers, monitors, instrument panels and controls.

> An operational analysis diagram supporting an objective approach to instrument room redesign. Ergonomic component positioning is based on usage, reach and field of vision. The position of the user is the center of the circle, with distance increasing outward. In this example analyzing navigation monitoring, the user requires a Sun workstation within reach and primary (head-on) view. Video monitors can be beyond reach, within secondary view. Seismic acquisition and processing monitors and printers can be even farther from central reach and view.
needlessly duplicated, and the working environment was cramped, uncomfortable and noisy. To a visitor’s eye, it lacked professionalism and forethought. A visiting client might question the value of entrusting a multimillion-dollar proprietary survey to workers in such surroundings.

Previous instrument room layouts developed in an evolutionary manner, referring back to what had been done before and using personal opinion to decide what might be improved. Modifications to room setups had been done by trial and error, experimenting with seating and equipment placement.

The new design approached the project from an analytical standpoint, from a basis of studied research and fact rather than opinion. For each work station, an operational analysis was undertaken that documented each operator’s equipment and assigned it a level in a positioning hierarchy. Levels were based on frequency of use, importance in routine and emergency operations, and relation to the user’s primary and secondary fields of vision, physical reach and communications with other work stations.

The preferred new design would make possible, for the first time, eye contact and verbal communication between crew members in two key roles—on-line navigation and on-line seismic acquisition. Eye contact is particularly important in times of high activity or stress; with eye contact it is easy to judge the level of anxiety or calm in a coworker, so crucial situations can be handled more efficiently. In theory, the new arrangement seemed good, but such a radical design required further evaluation before committing to construction.

A full-size mock-up was built, and a number of vessel crews participated in an evaluation program. This brought up-to-date field experience to the evaluation, encouraged crews to support the project and provided the design team with an opportunity to review new ideas. The concept was fine-tuned and construction was undertaken with the confidence that the design was right the first time. Operator comfort was considered; high-quality furniture and chairs were specified and careful attention was given to lighting levels. A double-glazed wall separated work stations from computer systems to minimize noise levels. This had the added benefit of allowing separate air-conditioning systems for computers and operators—a problem identified on previous vessels where temperatures had to be kept uncomfortably low to maximize computer reliability.

^ Full-size, whiteboard instrument room model for crew evaluation.

^ New instrument room pioneered on the Geco Gem-series vessels. Instrument positions and work environment are optimized for user comfort and productivity.
The first vessel with the new instrument room design was the *Geco Emerald* and all subsequent Gem-series vessels repeated the same design.

For the *Geco Eagle*, the same general plan was followed, with the addition of more computer workstations for onboard processing, conference rooms and a dedicated office for clients (top). The design added storage space for back-up computers and equipment, so that spares are kept in a controlled, accessible environment. A separate room contains network and telecommunication cables. In a further improvement, all seats in the instrument room were positioned to face forward for increased comfort in rough seas.

In their feedback, the crew commends the new design, especially the good visual communication and the large amount of workspace (left). Placing the observers at the same desk as the “Trilogist”—the operator of the Schlumberger TRILOGY quality-control system for sources and streamers—greatly facilitates teamwork. Initial skepticism toward the instrument room layout, specifically regarding the forward-facing aspect of all work areas, has been overcome. The ergonomic design has improved communication between the navigation, onboard processing and acquisition departments and proved to be a winner. The overall improvement in operational efficiency quickly paid for the time and effort that went into the redesign project, recouping costs by early in the second month of operation.
Real (Virtual) Training

Schlumberger places a strong emphasis on training for operations personnel. A modular training program gives vessel crews high exposure to a wide range of on-line, classroom, practical and self-tutorial instruction. However, the unprecedented levels of new technology carried onboard the Geco Eagle led the project team to seek additional training capability prior to the vessel’s launch. With much of the new technology managed from the streamer-control station, training in its use was critical to a smooth start-up for the new vessel.

At the Schlumberger training center in Asker, Norway, a training simulator was constructed to familiarize crews with the new technology before they even set foot on the vessel. A projection system and 150° curved display screen are used to create a virtual version of the Geco Eagle back deck (right).

The CAD simulations devised for the redesign study form the foundations of the training simulator. The system is similar in principle to a flight simulator, replicating the onboard environment including the Cyberbase chair, user interfaces, alarm panels and the closed-circuit television system. The renditions are realistic enough to include crew members working on the back deck (right).

Crews were first trained on back-deck procedures and best practices during normal streamer deployment and recovery operations. The simulator also provides experience in less common situations. For example, the simulator can test a trainee’s reactions to conditions that stray outside the parameters of safe towing. Turning the vessel, other ships crossing the streamers, drilling rigs, fishing nets, shallow water, changes in wind or currents and man overboard can all be simulated. Equipment problems such as malfunctioning streamer depth control, Monowing angle control, global positioning systems in the tail-buoys and winch controls can be reproduced for training purposes. Using the full suite of cases available in the simulator, the crew can be trained in all aspects of survey management. The training sessions are recorded and can be played back to review and improve how situations are handled.
Before **Geco Eagle** was launched, the simulator gave her future crew experience that could not have been found on any existing seismic vessel. It enhanced operational awareness and allowed them to build controls around clearly identified high-risk operations, reducing the possibility of error or accident.

After attending more than 40 training courses, the **Geco Eagle** crew was ready to take her to work offshore Brazil. The vessel had a smooth start-up and achieved high levels of daily production with 10 streamers right from the beginning. There were no operational problems with any of the equipment covered by the training programs.

The training simulator will continue to play an important role, not just for the **Geco Eagle** but also for other vessels that will be deploying large spreads in challenging operational environments. The software element is fully portable, enabling simulation to be used on board vessels to give further training as necessary [above]. Since the towed equipment is common to the whole Schlumberger fleet, there are also plans for crews of other vessels to take operational seminars using the simulator. In the meantime, the simulator is being used to develop and build the streamer configuration and train the crew of the **Geco Eagle** for the first 12-streamer job, scheduled for Autumn 1999. The combination of the latest technology and the added safety, comfort and efficiency built into the new design ensures that the **Geco Eagle** will be influential in shaping the future of seismic acquisition methods. —LS